Reliability Assessment of Distribution Networks Incorporating Regulator Requirements, Generic Network Equivalents and Smart Grid Functionalities

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Doctor of Philosophy

THE UNIVERSITY OF EDINBURGH

2017

Abstract

Over the past decades, the concepts and methods for reliability assessment have evolved from analysing the ability of individual components to operate without faults and as intended during their lifetime, into the comprehensive approaches for evaluating various engineering strategies for system planning, operation and maintenance studies. The conventional reliability assessment procedures now receive different perspectives in different engineering applications and this thesis aims to improve existing approaches by incorporating in the analysis: a) a more detailed and accurate models of LV and MV networks and their reliability equivalents, which are important for the analysis of transmission and sub-transmission networks, b) the variations in characteristics and parameters of LV and MV networks in different areas, specified as "generic" UK/Scottish highly-urban, urban, sub-urban and rural network models, c) the relevant requirements for network reliability performance imposed by Regulators on network operators, d) the actual aggregate load profiles of supplied customers and their correlation with typical daily variations of fault probabilities and repair times of considered network components, and e) some of the expected "smart grid" functionalities, e.g., increased use of network automation and reconfiguration schemes, as well as the higher penetration levels of distributed generation/storage resources.

The conventional reliability assessment procedures typically do not include, or only partially include the abovementioned important factors and aspects in the analysis. In order to demonstrate their importance, the analysis presented in the thesis implements both analytical and probabilistic reliability assessment methods in a number of scenarios and study cases with improved and more detailed "generic" LV and MV network models and their reliability equivalents. Their impact on network reliability performance is analysed and quantified in terms of the frequency and duration of long and short supply interruptions (SAIFI and SAIDI), as well as energy not supplied (ENS).

This thesis addresses another important aspect of conventional approaches, which often, if not always, provide separate indicators for the assessment of system-based reliability performance and for the assessment of customer-based reliability performance. The presented analysis attempts to more closely relate system reliability performance indicators, which generally correspond to a fictitious "average customer", to the actual "best-served" and "worst-served" customers in the considered networks. Here, it is shown that a more complex metric than individual reliability indicators should be used for the analysis, as there are different best-served and worst-served customers in terms of the frequency and duration of supply interruptions, as well as amounts of not supplied energy.

Finally, the analysis in the thesis considers some aspects of the anticipated transformation of existing networks into the future smart grids, which effectively require to re-evaluate the ways in which network reliability is approached at both planning and operational stages. Smart grids will feature significantly higher penetration levels of variable renewable-based distributed generation technologies (with or without energy storage), as well as the increased operational flexibility, automation and remote control facilities. In this context, the thesis evaluates some of the considered smart grid capabilities and functionalities, showing that improved system reliability performance might result in a deterioration of power quality performance. This is illustrated through the analysis of applied automation, reconfiguration and automatic reclosing/remote switching schemes, which are shown to reduce frequency and duration of long supply interruptions, but will ultimately result in more frequent and/or longer voltage sags and short interruptions. Similarly, distributed generation/storage resources might have strong positive impact on system reliability performance through the reduced power flows in local networks and provision of alternative supply points, even allowing for a fully independent off-grid operation in microgrids, but this may also result in the reduced power quality levels within the microgrids, or elsewhere in the network, e.g. due to a higher number of switching transfers and transients.

Lay Summary

Over the past decades, the concepts and methods for reliability assessment have evolved from analysing the ability of individual components to operate without faults and as intended during their lifetime, into the comprehensive approaches for evaluating various engineering strategies for system planning, operation and maintenance studies. The conventional reliability assessment procedures now receive different perspectives in different engineering applications and this thesis aims to improve existing approaches by incorporating in the analysis: a) a more detailed and accurate models of electrical distribution networks, b) the variations in characteristics and parameters of electrical distribution networks in different areas, c) the relevant requirements for network reliability performance imposed by Regulators on network operators, d) the actual customer load profiles and their correlation with daily fault probabilities and repair times of considered network components, and e) some of the expected "smart grid" functionalities.

The presented analysis attempts to more closely relate system reliability performance indicators, which generally correspond to a fictitious "average customer", to the actual "best-served" and "worst-served" customers in the considered networks. Here, it is shown that a more complex metric than individual reliability indicators should be used for the analysis, as there are different best-served and worst-served customers in terms of the frequency and duration of supply interruptions, as well as amounts of not supplied energy. Finally, the analysis in the thesis considers some aspects of the anticipated transformation of existing networks into the future smart grids, which effectively require to re-evaluate the ways in which network reliability is approached at both planning and operational stages. Smart grids will feature significantly higher penetration levels of variable renewable-based distributed generation technologies (with or without energy storage). In this context, the thesis evaluates some of the considered smart grid capabilities and functionalities, showing that improved system reliability performance might result in a deterioration of power quality performance.

Acknowledgements

Firstly I would like to thank my supervisor, Dr Sasa Djokic for his continuous guidance and support throughout the whole process of my PhD studies. Without his motivation, patience and honesty, there is no way that I could complete my studies.

I would like to acknowledge Malaysian Ministry of Higher Education and Universiti Malaysia Pahang for funding my studies in University of Edinburgh.

Many thanks to my colleagues and friends at the Institute of Energy Systems, especially all in room 4.120, it has been a real pleasure to work and socialise with you. A special mention to Adam, Anup, Camilla, Evangelos, George, Randy, Masum, Min and Jagadeesh. For Ignacio: you are really a great colleague and person, since you helped me a lot throughout my studies.

I really appreciate the time and efforts of my examination committee members, Professor Alfredo Vaccaro and Dr. Ewen Macpherson. Thank you for sharing your knowledge and advice with me as well as being kind in your assessment of this work.

A very special acknowledgement goes to my family for their endless support and encouragement that I could need. I am grateful to my parents and siblings, for their endless belief in me.

Finally, and most importantly, thanks to my wife Farida Zakaria and my children Airis Zulaikha and Aidil Zafeer for their support, belief, love and for being there for me. Three of you are the main reason why I completed my studies and I will be forever grateful to all of you.

Declaration

I declare that this thesis was composed by myself, that the work contained herein is my own, except where explicitly stated otherwise in the text, and that this work has not been submitted for any other degree or professional qualification except as specified.

Mohd Ikhwan Bin Muhammad Ridzuan

Contents

Figures and Tables

Figures

Tables

Acronyms and abbreviations

AC	Alternating Current
ADD	After Diversity Demand
AENS	Average Energy Not Supplied
AR	Automatic Recloser
ARCB	Automatic Recloser Circuit Breaker
ASAI	Average Service Availability Index
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CB	Circuit Breaker
CEER	Council of European Energy Regulators
CI	Customer Interruption
CIGRE	International Council of Large Electric Systems
CML	Customer Minutes Lost
CSA	Cross-sectional Area
CSP	Customer Supply Point
D	Double Line fault
DC	Direct Current
DG	Distributed Generation
DG	Double Line to Ground fault
DNO	Distribution Network Operator
DSM	Demand-side Management
EENS	Expected Energy Not Supplied
EHV	Extra High Voltage
ENA	Energy Network Association
ENS	Energy Not Supplied
EPR	Ethylene Propylene Rubber
ER	Engineering Recommendation
ES	Energy Storage
FiT	Feed-in-Tariff

FMEA	Failures Modes and Effects Analysis
GD	Group Demand
GSP	Guaranteed Standard of Performance
GSP	Group Supply Demand
HU	Highly-urban
HV	High Voltage
I	Inhabitants
IEA	International Energy Agency
LI	Long Interruption
LP	Load Point
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MCS	Monte Carlo Simulation
MDT	Mean Down Time
MG	Micro Generation
MTBF	Mean Time Between Failures
MTTF	Mean Time To Fail
MTTR	Mean Time To Repair
MUT	Mean Up Time
MV	Medium Voltage
NERC	North American Electric Reliability Council
NGET	National Grid Electricity Transmission
OFGEM	The Office of Gas and Electricity Markets
OHL	Overhead Lines
ORGS	Offshore Renewable Generating System
p.u.	per unit
PDF	Probability Distribution Function
pf	power factor
PSSE	Power System Simulator for Engineering
PV	Photovoltaic
PVC	Polyvinyl Chloride

QoS	Quality of Supply
R	Rural
RER	Renewable Energy Resources
RI	Re-Interruption
S	Single Line fault
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control And Data Acquisition
SI	Short Interruption
SoS	Security of Supply
SPD	Scottish Power Distribution
SQS	Supply Quality Standard
SU	Sub-urban
T	Three line/phase fault
TTF	Time To Fail
TTR	Time To Repair
TX	Transformer
U	Urban
UG	Underground cables
UK	United Kingdom
US	United States
XLPE	Cross-linked Polyethylene

Nomenclature

A_{1i}	Coefficient of fault rates/repair times for HU, U, SU, and R
A_{2i}	Coefficient of fault rates/repair times for HU, and U
A_{3i}	Coefficient of fault rates/repair times for SU, and R
A_{4i}	Coefficient of fault rates/repair times for HU, U, and SU
D_N	Discount for number of interruption
D_T	Discount for time interruption
I_{zph}	Maximum sustained current
N_l	Annual number of interruptions accumulated
P_f	Average power billed over the year
R_O	Zero sequence resistance
R_{ph}	Positive sequence resistance
S_{max}	Maximum apparent power
T_l	Annual interruption time accumulated
U_N	Threshold for number of interruptions in the supply zone
U_T	Time threshold of the supply zone
X_O	Zero sequence reactance
X_{ph}	Positive sequence reactance
Z_{SYS}	System impedance
Z_T	Transformer impedance
r_P	Parallel equivalent repair times
r_S	Series equivalent repair times
r_{eq}	Equivalent repair times
λ_P	Parallel equivalent fault rates
λ_S	Series equivalent fault rates
λ_{eq}	Equivalent fault rates
£	Pound sterling currency
€	Euro currency
h	hour

$A(t)$	Availability
Al	Aluminium
B	Susceptance
Cu	Cuprum
E	Annual energy supplied
FE	Energy consumption billed over the previous year, as established in the regulation of 12 January 1995 for electrical tariffs
N	Total number of network component
R	Resistance
$U(t)$	Unavailability
V	Voltage
X	Reactance
Z	Impedance
a	individual customer annual network tariff
b	yearly set base amount (for 2007, Swedish Government set it to SEK 41,100)
$f(t)$	Daily fault rates probabilities
int	Interruption
min	minute
r	Repair times
s	second
t	Time
β	shape parameter
δ	scale parameter
λ	Fault rates
σ	scale parameter

Chapter 1 Introduction

The existing electricity supply networks and grid infrastructures are currently undergoing significant changes, which can be generally termed as a “smart grid” transformation. These changes, which will be only more pronounced in the future, are mainly driven by the environmental concerns, requirements for the improved reliability and security of supply, as well as the development of new technical and technology solutions. For example, one of the important aspects of that ongoing transformation is significant growth of the zero or low-carbon emission and renewable energy sources generation technologies at practically all voltage levels, from a few (tens of) kW micro-generation units connected in low voltage (LV) networks, through medium-size power farms and parks with few hundreds kW or tens of MW connected to medium voltage (MV) networks, to a large-scale multi tens/hundreds MW and power plants connected to high voltage (HV) grid.

Particularly important is to analyse renewable-based generation units connected in distribution networks, i.e. distributed generation (DG), as these DG units are neither monitored, nor controlled by the network operators, or required to provide system support. The increasing penetration levels of DG, which has variable power outputs and is connected nearer to the points of consumption, introduces several challenges and technical problems for the operation, analysis and modelling of distribution networks. These challenges can be answered only if the developed models contain detailed information on the configurations and parameters of the MV and LV networks, correctly incorporate DG and loading profiles into the analysis and also reflect the (recently) updated regulations and grid codes set by distribution network operators (DNOs) and Energy Regulators. The other important characteristics of “smart grids” are increased levels of automation, remote control, monitoring and communication systems, which all might have a strong impact on the overall network performance. This thesis considers some of the abovementioned aspects of operation of modern electricity networks (towards their future smart grid transformation), which effectively require to re-evaluate the ways in which network reliability is approached at both planning and operational stages.

1.1 Background

The climate change concerns have resulted in the development of ambitious targets for the reduction of CO2 emission with, for example, the European Commission setting a target for 20% reduction of CO2 emissions by 2020 [1], while in the UK, the government has set a reduction of 80% of CO2 emissions by 2050 [2]. These ambitious targets pose a great challenge to all energy sectors in the UK, including the power supply networks. This thesis concentrates on the analysis of the electricity networks supplying residential (or domestic) customers, which account for around 15% of the total CO2 emission in the UK (emission associated with heat and electricity demands for residential use, [3]). In order for the residential load sector to help in meeting the above targets, there must be a reduction in the energy usage through, e.g., construction of more thermally efficient buildings and use of more efficient electrical equipment. The use of low and zero-carbon generation, i.e. DG, in LV and MV distribution networks is also one of the options for decarbonising electricity demands.

In order to successfully cope with the current and anticipated changes in distribution networks, e.g. implementation of DG, energy storage (ES) and demand-side management (DSM), existing electrical distribution networks must be able to maintain, if not improve, the existing levels of reliability, quality and continuity of supply. This is not only a general expectation, but is also regulated in related standards and legislation (e.g. guaranteed standard of performance, GSP, and security of supply, SoS, in the UK), where certain (accepted) levels of reliability and continuity of supply are specified. This thesis asserts that a full and accurate analysis of reliability performance of modern distribution networks must include the regulatory framework and requirements for reliability performance, both from the points of view of the DNOs and served customers. Moreover, the reliability assessment of modern networks should present an integrated methodology for both quantifying and predicting the network performance, which will integrate some aspects of the analysis which are typically not included in the conventional reliability approaches, such realistic load profiles, daily variations of probability of fault rates, etc. Finally, the previous approaches for the analysis of MV and, particularly, HV networks used oversimplified models of LV networks (represented with only peak active and reactive power demands), which do not allow for the assessment of the impact of the DG connected in LV networks and other changes in the operation of LV networks (e.g. implementation of automation and remote/smart controls). This thesis also considers more detailed and more accurate representations and models of reliability equivalents of LV and MV distribution networks, which is generally justified by one available DNO report [4], suggesting that most supply interruptions originate from the faults in MV and LV networks. Therefore, it is essential for an improved and updated reliability analysis to model in detail LV and MV network configurations, parameters and components that are supplying different types of residential customers, ranging from highly-urban and urban areas, through sub-urban areas, to rural areas.

1.2 Focus of the Research in This Thesis

This PhD research focuses on the formulation of improved methodologies for a more detailed reliability analysis of MV and LV distribution networks, incorporating the UK SoS and GSP regulatory requirements, specifying not only average/system reliability indices, but also the actual best-served and worst-served customers in the analysed “generic” network models. Furthermore, the thesis presents the elements of the analysis required for the assessment of the risks of penalties (or compensation payments) with respect to the prescribed limits for the duration of supply interruptions, which are of importance for the DNOs in planning their reliability strategies. Finally, the thesis analyses the impact of DG with or without dedicated ES in some of the possible operating scenarios, quantifying the benefits of the DG/ES in improving reliability performance of considered LV and MV distribution networks.

This thesis and presented analysis are continuation of the previous work in the system reliability area at the School of Engineering, the University of Edinburgh, most notably [5]. The PhD research in this thesis has put significant effort in devising further improvements of the previous work, where, for example, the generic residential LV and MV UK/Scottish network configurations and components are revised and a number of changes were made regarding the specification of the protection equipment and their operation in isolating different types of faults. Furthermore, the calculation of reliability equivalents is presented with more detailed equations, considering use of both circuit breakers and fuses in generic LV and MV network models. On the other hand, general information on the fault rates and repair times of network components from available literature and some DNO reports is thoroughly analysed in order to segregate the fault rates and repair times for the four generic networks supplying corresponding residential load sub-sectors.

1.2.1 Representation of Distribution Networks and Customer Related Factors

During the reliability performance analysis of MV and HV networks, LV networks are typically not represented in much detail. The most common equivalent form representation of LV network is by a simple aggregate ("lumped") load, specifying number of supplied customers and their peak active and reactive power demands (and sometimes minimum, or average demands, or daily load profiles) downstream of the MV point of aggregation, which is typically a primary or secondary distribution substation or transformer. However, the contributions of the LV networks to the overall system reliability performance in terms of frequency and, particularly, duration of LIs could be significant, although permanent LV faults usually do not result in interruptions of a large number of customers. Therefore, in order to have realistic estimation of reliability results, it is essential to have accurate models of LV distribution networks, which are in this thesis modelled with much more details regarding the configurations, parameters and components of the four generic LV and MV network models supplying highly-urban, urban, sub-urban and rural residential load sub-sectors.

The formulation of more detailed and more accurate reliability equivalent models is also accompanied by the use of the actual demand patterns and load profiles of residential customers, which allowed to obtain more realistic results for the reliability performance, i.e. to correlate the time-varying demands with the specific moment of fault occurrence (also represented by a various daily probabilities) for determining whether the supply to the loads/customers will be interrupted, or not. As the typical load profiles depend on the seasonal demand variations over the course of the year, the used load profiles correspond to three typical loading conditions in the UK/Scottish networks, such as the average loading for typical spring/autumn demand, maximum for winter demand and minimum for summer demand. These three loading conditions are represented in terms of differences in active/reactive power demands and changes in load profile curves (as the daily load profile plots), reflecting annual changes in e.g. ambient temperature and corresponding use of electrical heating/cooling loads.

1.2.2 Incorporation of Regulator Requirements

Distribution network operators (DNOs) are generally aiming to provide the high levels of power supply reliability (at least within the certain targets and limits specified in the related standards and legislative documents), while at the same time reducing the capital and maintenance costs of operating their networks, as this will result in lower electricity bills for their customers (affordability of supply). However, the recent statistics show that this is not an easy task, as 14% or the UK DNOs have been penalized for not achieving customer interruption (CI) annual targets imposed by Regulator (OFGEM in the UK), while 50% of DNOs exceeded their annual target limit for customer minutes lost (CML), [6]. Besides maintaining their network performance within the annual targets, the DNOs must also satisfy additional requirements for the maximum restoration times and frequency of long supply interruptions, which protect customers from experiencing too long and too frequent interruptions. After these requirements have been set, the DNOs will be responsible to restore supply to customers within a certain period of time, as otherwise they will be penalised. Accordingly, this thesis critically reviewed some of the commonly used input data for reliability analysis (e.g. reported repair times of network components) with respect to existing SoS and GSP continuity supply requirement and proposed not only some changes in their values, but also to include these requirements in the standard reliability assessment procedures. This is important from the DNOs' point of view, as it will help in deciding on the required or appropriate planning, operation and maintenance strategies, in order to avoid situations in which their reliability performance is below the specified annual targets, as well as for efficient managing of penalty/compensation payment risks.

1.2.3 Differentiation Between Average, Best and Worst-Served Customers

In most of the existing literature, the result of the reliability analysis are commonly presented as system/average reliability indices, corresponding to a fictitious "average customer" [7, 8, 9, 10, 11, 12, 13]. The DNOs also report their network reliability performance in terms of system indices and average customer performance, [14, 15, 16]. These reports and approaches do not provide any information on the actual customers, e.g. in terms of the best-served and worst-served customers in analysed networks. Additionally, evaluation of risks for frequency and duration of interruptions is unclear if system average customer indices are used, while evaluated risks are easy to interpret for best-served and worst-served customers.

This thesis does not question the use of average/system reliability indices for the purpose of providing information regarding the overall network performance, but suggests that an improved reliability assessment methodology should also provide information on the actual served customers and their "experience" with the reliability of the networks to which they are connected. In other words, it is important to provide information regarding the best, the worst and the average-served customers, as this will allow to both compare and interpret the obtained results of the reliability analysis, allowing to target specific actions and measures for improving reliability performance and reducing penalty risks with a higher level of confidence (than when only system average results are used).

1.2.4 Inclusion of DG and ES in the Analysis

The evolution and transformation of existing networks into the future 'smart grids', with respect to the increased numbers of both DG and ES systems, can be divided in the three following steps or stages: from passive network integration, via reactive network integration, to active network integration, [17]. Implementation of advanced monitoring, sensing, communication and control systems in distribution networks will allow DNOs to have better control and management of their networks (planning and operation) and to integrate DG/ES resources in safe, economic and efficient ways. In this thesis, two types of active DG network integration with dedicated ES are analysed. The first type is use of DG and ES for reducing peak demands, while the second type is use of DG and ES for reducing demands during the times of increased probability of faults.

1.3 Research Scope and Objectives

The first objective of this PhD was to identify missing elements, information and data related to the network components and network models required for the reliability analysis, to update the existing and available networks and network components, and to employ these for the analysis of the typical UK/Scottish residential LV and MV distribution networks. Accordingly, these typical networks are divided into four different generic residential load sub-sectors, from metropolitan and city areas, to sub-urban and remote rural areas. Detailed network configurations, descriptions of network components and specifications of parameters are provided for all considered generic LV and MV networks, including relevant loading conditions, types of the faults (permanent vs transient, single-, double- and three-phase faults). The required data and information are collected from an extensive surveying and searching of the UK, Scottish, European (and beyond) DNO reports, as well as manufacturers of the network equipment. In addition to that, the reliability input data (e.g. fault rates and MTTR) are divided into different residential load sub-sectors based on the location, type of the switchgear (e.g. indoor or outdoor), loading conditions and number of other relevant factors.

The second objective of this PhD was to propose improvements to the existing approaches for the assessment of the network reliability performance, including both analytical and probabilistic techniques. Accordingly, the thesis applied both analytical and probabilistic (e.g. Monte Carlo simulation) approaches to assess the frequency and duration of supply interruptions, expressed them in terms of the system or customer-based reliability indices and analysed them in a number of different scenarios. The results of the analytical and probabilistic approaches are often directly compared (mean values of calculated reliability indices), in order to both check their accuracy and allow for an additional interpretation of results from a single approach.

Available reports, recording and statistics are processed to identify and select the most realistic input data for the assessment of network performance (mean fault rates and mean repair times), which is then expressed and quantified through the set of standard reliability indices (SAIFI, MAIFI, CAIDI, SAIDI, ENS, etc.). The particular focus was on the continuity of supply of LV residential customers, where the conventional reliability assessment procedures are extended by including actual loading conditions, accurate network models, empirical daily fault probability distribution and ratio of long to short supply interruptions, based on the analysis of statistics on permanent and temporary faults, applied types and settings of protection systems and estimated probabilities of different fault types, which are all considered separately for the four generic LV and MV networks.

Finally, the third objective of this PhD was to analyse the impact of the implementation of “smart grid” technologies and functionalities on the network reliability performance, i.e. DG and energy storage installed in the LV distribution networks. This part of the analysis showed that the DG and ES have potential to improve network reliability performance, if they are properly coordinated and operated (e.g. in the weakest network areas, where the reliability performance is expressed in the lowest SAIFI/SAIDI values). As the renewable-based DG has variable power outputs, the analysis included combining DG with the dedicated ES, in order to maximise the benefits in improving the network reliability performance. In order to avoid underestimation of network reliability performance, this part of the analysis required correct modelling of distribution networks in which DG is implemented, which was based on the previously developed general methodology for the formulation of improved reliability equivalent models of LV distribution networks. These equivalent reliability models were based on the aggregation of individual network components in specific network configurations (four generic LV and MV network models), helping to reduce network complexity and computational times, while preserving the accuracy of the reliability performance assessment procedures.

In concluding this section, the scope of this PhD thesis was to improve conventional methodologies for reliability assessment of existing and future LV and MV distribution networks. This is important, as conventional reliability assessment procedures do not include, or only partially include a number of factors that can strongly impact the output results for the network reliability performance. Accordingly, changes, modifications and additions in this thesis can be grouped in the following categories: a) a more detailed and accurate models of LV and MV networks and their reliability equivalents, b) the variations in characteristics and parameters of LV and MV networks in different areas, specified as "generic" UK/Scottish highly-urban, urban, sub-urban and rural network models, c) the relevant requirements for network reliability performance imposed by Regulators on network operators, d) the actual aggregate load profiles of supplied customers and their correlation with typical daily variations of fault probabilities and repair times of considered network components, e) consideration of reliability performance in terms of not only average, but also best- and worst-served customers, and f) analysis of "smart grid" functionalities, i.e. increased use of network automation and reconfiguration schemes, as well as the higher penetration levels of distributed generation/storage resources.

1.4 Thesis Contributions to Knowledge.

The results from this research have been presented in four international conferences papers and two journal papers (under preparation). In addition to that, a section of the results has been presented at the Durham Risk Day 2014. The contributions can be summarised as below:

- Modelling of the generic residential LV and MV UK distribution networks:
  - Detailed configurations and parameters are presented.
  - Selection of network components based on the location and loading conditions of each residential load sub-sector, or network area.
- Assessment of network reliability performance with influence of load model and "smart grid" functionalities:
  - Analysis of impact of the connected DG on reliability improvements.
  - Application of dedicated ES in typical scenarios, for maximising the benefits of renewable-based DG.
- Contributions to the network reliability performance analysis:
  - Improved analytical and probabilistic procedures for the application in existing and future LV and MV networks.
  - Inclusion of load profiles, long interruptions to short interruptions (LI/SI) ratios and daily fault probability distribution in the probabilistic approach.
- Formulation of more accurate reliability equivalents of LV distribution networks:
  - Implementation of the full three-phase models, instead of a single-line representation of LV networks.
  - Differentiation between different types of faults (resulting in LIs or SIs) for underground-cable or overhead-line LV and MV networks.
  - Specification of more realistic reliability input data (fault rates and repair times) and fault types (permanent/temporary and single/double/three-phase) for all considered generic network models and load sub-sectors.
- Specification of penalty risk assessment procedure in terms of durations of LIs affecting residential customers:

  - Analysis of the recent changes in the UK Regulator requirements (for LI duration from 18 hours to 12 hours) on the increased probability of paying the penalty/compensation.
  - The assessment of network reliability performance not only in terms of average (system-based) indices, but also regarding the actual best- and worst-served customers (separately for frequency and duration of LIs).
- An example of applying presented reliability assessment approaches outside the considered LV/MV distribution networks, for the performance assessment of an offshore power plant.

1.5 Thesis Structure

After this introductory chapter, Chapter 2 of the thesis discusses the theoretical background for reliability assessment and presents a short overview of literature relevant for this PhD research. An overview of the general power system architecture is presented, along with the main characteristics of the UK (and European and wider) electricity supply networks. The term "Distributed Generation (DG)" is clearly defined and a literature review of the impact and effects of integration of DG on the distribution network performances is presented. An overview of the most widely used reliability concepts, metrics and indicators is also presented, including the UK practices.

Chapter 3 discusses the techniques and criteria used in this research for the reliability evaluation and calculation of the system and customer-based indices. This includes both analytical approaches (limited with average/mean input data for, e.g., loading conditions, mean fault rates and mean repair times) and probabilistic approaches (Monte Carlo Simulation, MCS, procedures modified with the inclusion of actual loading condition and the use of daily fault probability distributions). The uncertainty of the output results and convergence criteria during the MCS-based calculation of reliability indices is also discussed. The application of the analytical and probabilistic approaches is presented and an example of the reliability performance assessment of an offshore power plant and network is provided.

Chapter 4 provides detailed information for improved analysis and modelling of MV and LV distribution networks. This part of the work focuses on network modelling, where a wide range of specifications and parameters of the network components is provided and discussed, including the configurations of generic LV and MV networks supplying residential UK customers in the four corresponding load sub-sectors. The important criteria and conditions for modelling LV and MV distribution networks are also discussed, based on the network operating conditions, applied types and settings of protection systems and occurrence of different fault types, as well as a more realistic representation of seasonal changes in residential load profiles.

In Chapter 5, the analysis concentrated on the formulation of more accurate reliability equivalents of the modelled LV distribution networks. This chapter starts with provision of a full and detailed documentation of mean fault rates and mean repair times as the main input data for reliability analysis. As the mean fault rates and mean repair times are provided without making distinction between different networks (e.g. from urban to rural areas), the corresponding values are segregated into sets of four values required for the analysis of the four generic LV and MV distribution networks. Next, an improved methodology for the calculation of the reliability equivalents of LV networks is presented, which simplify the analysis, while preserving the accuracy of the calculated reliability indices. The application of both analytical and MCS algorithms is discussed and obtained results are compared for typical scenarios related to reliability analysis of distribution network functionalities and equivalent network models.

In Chapter 6, a more realistic approach for reliability assessment is presented, acknowledging importance of including both the functionalities and settings of the applied protection devices and requirements from SoS, GSP and Regulator in the analysis. This required a thorough review of the changes in the related security and reliability of supply requirements recently made by the UK Regulator (e.g. more stringent requirements for the maximum restoration times), which was then applied for the calculation of the risks of penalty/compensation payments from the system and customer-based points of view. Finally, the potential improvements/benefits towards reducing the frequency and duration of customer interruptions due to implementation of DG with or without dedicated ES system are analysed using the MCS approach with time-sequential calculation. The results of different scenarios of active DG & ES network integration are presented and compared ("peak demand shaving" and "reliability-based demand reducing").

The last chapter, Chapter 7, gives a review of the main contributions and results of this PhD research, and discusses the application of the presented methodologies for the improved reliability analysis of (planning, operation and management of) existing and future distribution networks. This chapter also suggests some areas for the future work and provides some general conclusions.

Chapter 2 Assessment of Network Reliability Performance: Background and Metrics

This chapter discusses the theoretical background for the assessment of network reliability performance in relation to some general principle of operation of power supply systems, i.e. the three basic segments of generation, transmission and distribution networks. This is followed by a brief overview of related literature, where reliability metrics and indices commonly used in different countries and in the UK are specified. This chapter also gives an initial review of distributed generation (DG), including its impact on traditional distribution networks. Three general levels of DG integration that follow ongoing evolution/transformation of the distribution networks with the increasing numbers of DG are also discussed, from passive DG network integration, through reactive DG network integration, to active DG system management.

2.1 The Power Supply System

The main aim of power supply systems is to satisfy the customers' demands for electrical energy, where electricity produced from raw energy sources (e.g. hydro, coal, natural gas, wind, solar, etc.) is transferred through the transmission and distribution networks to the "end-use points of utilisation". Some of the basic principles of operation of power supply systems are discussed in further text in relation to the assessment of network reliability performance.

2.1.1 Conventional power system architecture

The power supply systems are made up of three basic segments: generation, transmission, and distribution. These three segments differ in configurations, voltage levels, sizes, types and settings of applied protection systems, main principles of operation, functionalities and target objectives. Traditionally, the electrical power is generated centrally, by large power plants with capacities typically in the order of several hundred Megawatt (MW), or higher. The power is then transformed into high voltage (HV) for bulk transmission over larger distances to the main load supply points, where it is converted to medium voltage (MV) for distribution and supply of larger customers and, finally, to low voltage (LV) for supplying customers in various load sectors (e.g. residential and smaller commercial).

In the conventional power system architecture, the distribution network is viewed as a passive network, in which power flows are unidirectional, always from the transmission system to the many load points in the distribution networks. However, in recent years, particularly renewable-based and therefore variable generation sources are being connected in larger numbers at the distribution level, thus changing the operation of distribution networks from passive to active. This has created new challenges for network operators, as these modern electricity grids are increasingly operated under conditions which are not planned in their original design.

2.1.2 General characteristics of the UK networks

Larger transmission networks are managed and operated by regional transmission companies. In the UK, these are currently the National Grid Electricity Transmission PLC (NGET) for England and Wales, Scottish Power Transmission Limited for southern Scotland, and Scottish Hydro Electric Transmission Limited for northern Scotland and the Scottish islands. However, the transmission network across the UK as a whole is operated by a single system operator, which is currently the National Grid Electricity Transmission PLC (NGET). National Grid balances the system and manages the generation outputs to ensure matching of demands, therefore keeping system voltages and frequency within the acceptable limits.

The UK transmission system operates at 400 kV, 275 kV and 132 kV voltage levels. In England and Wales, voltage levels below 275 kV are normally regarded as the distribution and sub-transmission networks, but 132 kV level is considered to be part of transmission system in Scotland. Electricity distribution to end-users is performed at lower voltages, typically 33 kV, 11 kV, 6.6 kV, and 0.4 kV. The distribution system is a much denser layer of networks, which ultimately connect all end-users to the electricity grid. The interface between the transmission and distribution systems occurs at the grid supply transformer substations (so called "super grid transformers", typically 275/33 kV or 132/33 kV in Scotland, and 275/132 kV or 400/132 kV in the rest of the UK).

Distribution network operators (DNOs) own and operate the distribution networks that bring electricity from the transmission network to the end-users, which are generally divided in industrial, commercial, residential/domestic and other load sectors, or customer classes. Currently, there are 14 licensed DNOs in the UK, each responsible for a regional distribution services area. DNOs do not sell electricity to the end-users, as energy retail sector/service is separated from the operation, but maintain and upgrade networks and all related facilities in order to provide continuous and high quality supply of electricity to all customers.

2.2 Assessment of Network Reliability Performance

Network reliability is one of the most important aspects of operation of electricity supply systems, which is closely monitored not only by the DNOs, but also by the Energy Regulators (OFGEM in the UK). Consequently, if the DNOs do not aim to continuously improve, or at least maintain certain levels of reliability performance of their networks, this will result in severe penalties by the Regulators and will significantly affects DNOs ability to gain new customers and keep the existing ones.

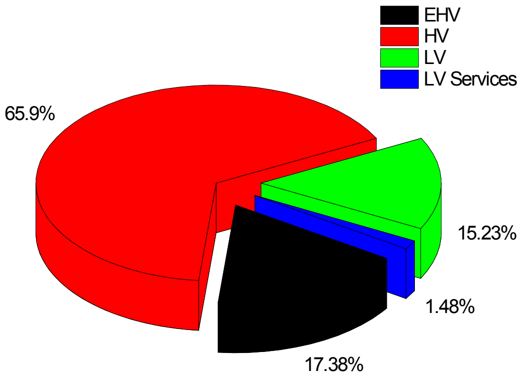
The networks reliability performance is quantified and assessed through a number of indices, which generally vary from one country to another. The DNOs from the United States (US) and most of the European countries quantify the network reliability performance using indices related to long supply interruptions (LIs) from [18]: system average interruption frequency index, SAIFI, system average interruption duration index, SAIDI, momentary average interruption index, MAIFI, and energy not supplied index, ENS. The terms used in the UK are different, as the UK DNOs report to the Regulator two reliability indices, for which the Regulator specifies annual target values: customer interruption (CI), calculated per 100 customers (interrupted) and customer minutes loss (CML), calculated in minutes. CI and CML basically correspond to SAIFI and SAIDI indices, respectively. In addition to that, the UK DNOs also report number of short interruption (SIs), although currently there is no specified target for it.

In terms of the distinction between long interruptions (LIs) and short interruptions (SIs) of supply, there is a difference in the duration limits between European countries and the US. The DNOs in Europe typically define LI as at least three minutes long interruption of supply [19], while one minute limit is used in the US, [18]. As the Regulators impose targets for the annual reliability performance, the DNOs have to strategically plan the operation of their networks, both in technical and economic terms, in order to achieve or perform better than the imposed reliability targets with only a reasonable increase of electricity costs for their customers. However, the recent UK statistics show that current DNOs planning and operation strategies for reliability performance were not always successfully implemented. For example, more than 14% of the UK DNOs were penalised for not achieving specified CI targets, while 50% of them were not able to meet their CML targets in one considered year [6]. Therefore, it is important for DNOs to apply as accurate and as comprehensive reliability assessment methods and procedures as reasonably possible (e.g. in computational sense, or by including currently neglected factors that may affect the calculated reliability performance) and this thesis discusses some of the possible ways for improving existing approaches for reliability assessment.

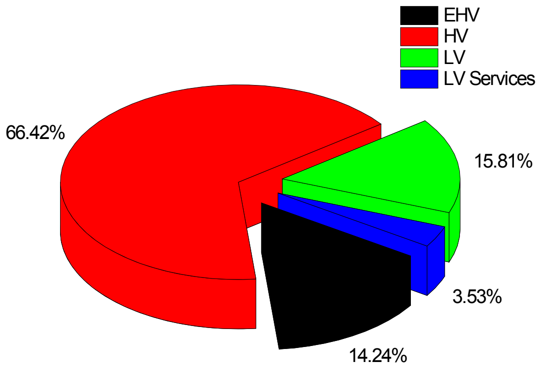
The distribution of permanent and transient faults into LI or SI depend on the protection and/or configuration of the network. For example, permanent faults (longer than 3 minutes in Europe) normally result in LIs, but can turn into SIs if the network can be reconfigured in less than 3 minutes and provide alternative supply to all customers. Another important factor in reliability assessment which is less researched is the occurrence of multiple simultaneous faults in the networks. These cases are due to cascading effect (e.g. overloading of more than one component), stressing the network beyond its N-1 security limits. For example, the MV urban network is designed with two identical parallel 33/11 kV transformers and if one of the transformers is faulted, the other transformer may also trip if it is overloaded during that period (cascading effect).

Another objective of DNOs is to increase the value of their business and services they are providing to the customers, e.g. to increase the reliability performance, but at the same time lower the expenses for customers. This requires to apply detailed design, planning and operation analyses and studies of distribution networks, where the dominant impact on reliability performance, as seen by the customers, originates from MV and LV networks. In the UK, it is reported that about 82% of CI and 85% of CML figures are caused by the faults and similar unplanned incidents in LV and MV networks, with voltage levels from 0.4 kV up to 20 kV [20]. Figure 2.1 illustrates reported numbers for frequency and duration of supply interruptions for one Scottish DNO, by the voltage level at which they occurred. Typical nomenclature used by UK DNOs is to disaggregate the MV level, classified as follows:

- Extra High Voltage (EHV) – voltage greater than 20kV, but less than 132kV;
- High Voltage (HV) – voltage from 1 kV up to 20kV;
- Low Voltage (LV) – voltage less than 1 kV;
- LV services – the LV service entry line, connecting customers to the electricity supply network.



a) CI proportion by voltage level



b) CML proportion by voltage level

Figure 2.1: Proportion of customer supply interruptions by voltage level, Scottish Power Distribution Report 2012/13 [20].

For the improved analysis and assessment of reliability performance, DNOs must model their networks with detailed configurations, with all required parameters and with accurate input data. Particularly important is to obtain accurate information on fault rates and mean repair times of individual network components (Fig. 2.1), as often parts of the networks operating at lower-voltage levels are represented by lumped aggregated models, providing only information on active and reactive power demands, in order to simplify the analysis and reduce the computational times. Additional important reasons for revising conventional reliability assessment approaches are the changes in the structure and operation of existing distribution networks, e.g. due to the implementation of new technologies (distributed generation, increased automation and remote control, etc.) and due to the further deregulation of the electricity market and provision of new services (e.g. demand-side management and time-of-use tariffs).

2.2.1 Definition of Reliability

Initially, the reliability concepts evolved from analysing the ability of the network components (individual components, or groups of components) to operate without faults and as intended during their lifetime. In recent years, reliability performance was redefined as the ability of the considered network to supply all connected customers, where (overall) continuity of supply is assessed in terms of the system-based (i.e. system average values of) reliability indices. It should be also noted that the concepts of availability and security have always been closely related to reliability analysis and since all three concepts are closely related, there should be a clear distinction between their actual meanings. All three concepts are generally used for the analysis of the power system as a whole, but when the focus is on an individual network component, only the concepts of reliability and availability can be applied (e.g. of a generator, a cable, or a transformer). Accordingly, the results of the reliability and availability analysis can be obtained for a larger part of the network, or extended to the whole network, in order to identify the influence and impact of a particular component on the reliability of the system in which this component is used.

The flexibility in defining and implementing reliability analysis to the specific part(s) of the system allows to perform reliability analysis from the point of view of particular customers. This is demonstrated in Chapter 6, where system-average reliability indices, which do not necessarily relate to any actual customer in the considered network, are compared with the corresponding results for the actual “best served” and “worst served” customers.

Based on the North American Electric Reliability Council (NERC), power system reliability is defined as “the degree to which the performance of the electrical system elements result in power being delivered to consumers within the accepted standard and in the amount desired”, [21]. In addition to that, NERC considers adequacy and security as the major factors for reliability analysis. Adequacy is defined as “the ability of a system to supply aggregate electric power and energy requirements of the consumers at all times”. Typically, the concept of adequacy is broadly used in the generation and transmission systems, where the energy generation resources, including capacity reserves, are specified so that demand during peak conditions can be meet and sufficient system capacity reserves are provided in cases of various (credible) contingencies. Similarly to the evolving concept of reliability, implementation of new technologies, services and functionalities in the distribution networks, such as DG, energy storage (ES), demand-side management (DSM), etc., will also impact the changes in the traditional adequacy concepts.

Availability, *A(t)*, is defined as the total number of hours in a calendar year for which a network component, a part of the network, or the whole network/system is available, i.e. capable of operating as intended and in normal operating conditions. Unavailability, *U(t)*, is the inverse of availability, i.e. the total number of hours in a calendar year for which normal operation of a network component, or a part of the network, or the whole network/system is interrupted, e.g. due to a fault (unplanned event), or a scheduled maintenance/servicing (planned event). Different formulas are often provided in the literature for quantifying availability. An example is [22]:

$$A(t) = \frac{up\ time}{up\ time + down\ time} \tag{2.1}$$

where: uptime is the time the network component(s) or the whole system is in normal operation, and downtime is the time when not in operation. Unavailability is then expressed as:

$$U(t) = 1 - A(t) \tag{2.2}$$

Figure 2.2 illustrates some of the quantities used for a more detailed analysis of the temporal aspects of reliability assessment.

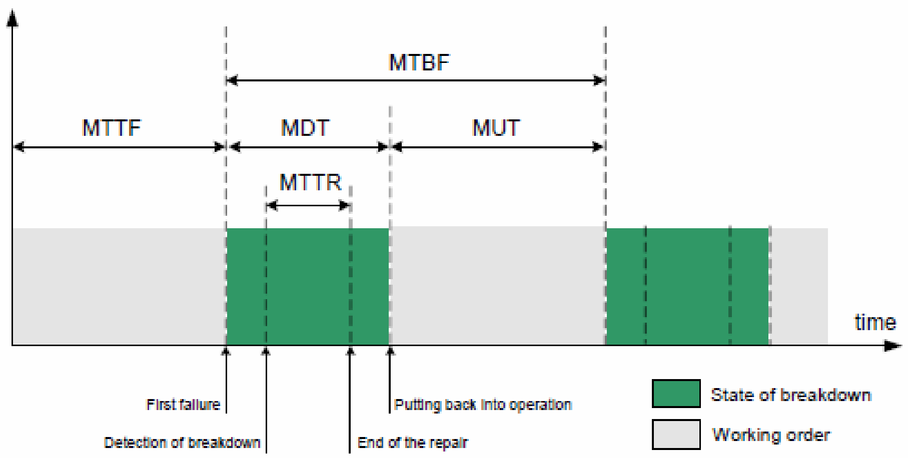


Figure 2.2: Temporal aspects of reliability assessment process [23].

In Figure 2.2, [23]:

- Mean time to fail (MTTF) – average time of normal operation of a component or a system, before the first failure occur.
- Mean time to repair (MTTR) – average time required for repairing the faulted component or system, so it can be returned to the initial operation state.
- Mean time between failures (MTBF) – average time between two consecutive failures of a repairable component or system.
- Mean up time (MUT) – average time of a normal operation after the repair.
- Mean down time (MDT) – average time spent in failure state: sum of times for detecting the failure after it occurs, repairing the failure and putting back repaired component into operation.

An alternative definition of availability uses the time of normal operation (i.e. the time between the two consecutive faults, or time before the first fault) and the time for which the component or system is out of service (i.e. the time required to repair the faulted component/system), [24]:

$$A(t) = \frac{MTBF}{MTBF + MTTR} \tag{2.3}$$

The difference between (2.1) and (2.3) is that MDT includes the MTTR and periods of time before the faulty condition has become apparent and until the component is repaired and put back into service. In detailed reliability assessment applications, MDT is applied only when there are unplanned/forced outages, while MTTR is considered for planned outages, or during the maintenance and servicing periods. In general case, the availability calculation does not specify the difference between the unplanned and planned outages and is therefore possible to consider both types of outages in the analysis.

Finally, security is defined as the ability of a power supply system to respond to disturbances and transient events without becoming unstable and/or resulting in faults that require disconnection of (a large number of) customers, or not satisfying customers' supply requirements [25]. The term security is therefore closely associated with both reliability assessment and analysis of system transfers from one operating state to another, typically within a relatively short period of times. Accordingly, security should assess ability of the system to withstand sudden disturbances (e.g. faults and contingencies) and minimize their impact on the system and supplied customers [21].

2.2.2 Metrics for Reliability Assessment

In existing literature and practice, several sets of indices have been proposed for the assessment and evaluation of the power systems reliability. Each of the three main segments of the power system (i.e. generation, transmission and distribution part) has its own specified indices. For example, loss of load probability (LOLP) and loss of load expectation (LOLE) indices are used for generation, while bulk power interruption index (BPII) and bulk power energy curtailment index (BPECI) indices are used for the analysis of transmission systems. A more detailed description of the reliability indices of each segment related to the system and end-load assessment, is available in [25, 26, 27]. The various sets of indices and indicators are used for quantifying, benchmarking, comparing and exchanging information on network reliability performance, after which targets can be set or adopted for further improvement and analysis of the different operating and loading conditions of the system.

This thesis focuses on the reliability indices related to distribution networks. Every year, DNOs are required to report a specified set of reliability indices to the Regulators, which directly quantify the number and duration of supply interruptions. These sets of indices are not globally uniform and vary from one Regulator in one country to another Regulator/country. Based on the quality of the electricity supply report [14], presented by the Council of European Energy Regulators (CEER), most countries in Europe define their own reliability indices, and this report provides a comprehensive list of reliability indices used by the European countries. Although the terms used by the DNOs in Europe are different, the computational procedures, the calculation processes and formulas used are similar. For instance, in the UK, the calculation of the number of customers with interrupted service and the duration of interruption reported to the Regulator is practically identical to the computational procedure of a set of indices considered by the DNOs in Italy, Germany, The Netherlands (but also the US and Canada), which calculate the reliability indices according to [18]. However, the terms used are somewhat different.

2.2.3 Reliability Indices

The basic reliability indices for network performance assessment are usually related to basic reliability parameters, such as mean fault rate, λ, expressed in faults/year, repair time, r, or mean time to repair, MTTR, expressed in hours/fault, as well as annual repair time, or unavailability, U, in hours/year. Typically, these parameters are given as input data for network components. All of these indices are considered through a series-parallel combination of network components, in order to assess the reliability performance of the whole system, part of the system or specific customers.

The basic calculation of reliability indices for series-connected components is based on the following equations [25]:

$$\lambda_s = \sum_{i=1}^{N} \lambda_i \tag{2.4}$$

$$r_s = \frac{\sum_{i=1}^{N} (\lambda_i r_i)}{\sum_{i=1}^{N} \lambda_i} \tag{2.5}$$

$$U_s = \lambda_s r_s \tag{2.6}$$

where: N is the total number of network components; λ_i is the mean fault rate of component i; r_i is the MTTR of component i; λ_s is the total fault rate of N series-connected components; r_s is the total MTTR of N series-connected components; and U_s is the total unavailability of N series-connected components.

The basic calculation of reliability indices for parallel-connected components is based on the following equations [25]:

$$\lambda_p = \lambda_1 \cdot \lambda_2 \cdot \ldots \cdot \lambda_{N-1} \cdot \lambda_N \begin{pmatrix} r_1 r_2 + \cdots + r_1 r_{N-1} \\ + r_1 r_N + \cdots + r_2 r_{N-1} + r_2 r_N \end{pmatrix} \quad (2.7)$$

$$r_p = \frac{r_1 \cdot r_2 \cdot \ldots \cdot r_{N-1} \cdot r_N}{r_1 r_2 + \cdots + r_1 r_{N-1} + r_1 r_N + \cdots + r_2 r_{N-1} + r_2 r_N} \quad (2.8)$$

$$U_p = (\lambda_1 \cdot \lambda_2 \cdot \ldots \cdot \lambda_{N-1} \cdot \lambda_N)(r_1 \cdot r_2 \cdot \ldots \cdot (r_{N-1} \cdot r_N) \quad (2.9)$$

where: N is the total number of network components; λ_1, λ_2 and λ_N are the fault rates of network components 1, 2 and N; r_1, r_2 and r_N are the MTTR of network component 1, 2 and N; λ_p is the total fault rate of parallel-connected components; r_p is the total MTTR of parallel-connected components; and U_p is the total unavailability of parallel-connected components.

Repair process of a faulted component/system can be modelled using an up-down-up cycle, i.e. normal operation, fault, repair and again normal operation, Figure 2.3, which is closely correlated with Figure 2.2.

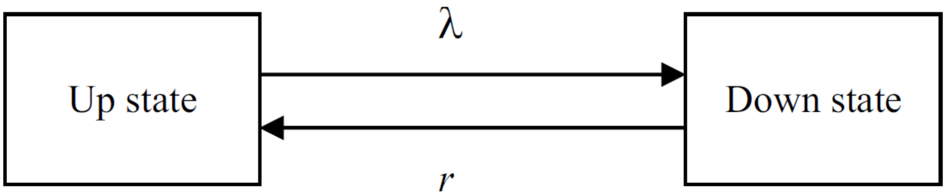


Figure 2.3: Two-state diagram of repairable components [28].

Typically, reliability performance of a distribution network is quantified using separate indices for estimating the frequency and duration of long and short supply interruptions.

System average interruption frequency index, SAIFI, is defined as the average number of customer interruptions lasting longer than a specified duration (e.g. one minute in [18]) per customer served, which are recorded during a specified time period, normally a year. SAIFI is expressed in long interruption/customer/year:

$$SAIFI = \frac{Total\ number\ of\ customers\ interrupted\ (by\ LI)}{Total\ number\ of\ customers\ served} \quad (2.10)$$

System average interruption duration index, SAIDI, is defined as the average duration of interruption in hours, per customer, during a designated time period, also normally a year. In general, SAIDI is calculated and expressed in hours/customer/year, although some of European DNOs use minutes instead of hours:

$$SAIDI = \frac{Total\ customer\ interruption\ durations\ (by\ LI)}{Total\ number\ of\ customer\ served} \qquad (2.11)$$

Equivalent fault rate, λ, and equivalent unavailability, U, have similarities with the SAIFI and SAIDI indices, respectively, as long as the total number of customers affected by the considered interruptions is supplied from the same network equipment stated in the outage condition (e.g. all customers are connected with the same transformer). Furthermore, the SAIFI index and equivalent fault rate are expressed in faults or interruptions per year, while the SAIDI index and equivalent unavailability are expressed in hours per year.

Customer average interruption duration index, CAIDI, is defined as the average duration of long supply interruptions, expressed in hours per customer interrupted:

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{Total\ customer\ interruption\ durations}{Total\ number\ of\ customers\ interrupted} \qquad (2.12)$$

The SAIFI, SAIDI, and CAIDI indices cannot differentiate between the different types of customers, as they “weigh” different customers equally. For instance, one customer may represent a large industrial load (in the MVA region) while the others may contain small residential load (in a few kVA range).

In the UK, DNOs report to the Regulator two indices, which are the customer interruptions (CI) and customer minutes lost (CML), where CI is calculated per 100 customers and duration of supply interruption should be at least three minutes, in order to be classified as long interruption (LI) [19]. The CI index excludes repetitive interruptions of customers during the same incident, so these interruptions are counted as re-interruptions (RI) of the supply. The CI is expressed in number of customers interrupted per year per 100 customers and calculated as [29]:

$$CI = \frac{The\ sum\ of\ the\ number\ of\ customers\ interrupted\ for\ all\ incidents}{Total\ number\ of\ customers} \cdot 100 \quad (2.13)$$

where the total number of customers includes all customers connected to a considered distribution network via dedicated electricity meter.

The CML is defined as the average duration of long interruptions (in minutes) per year and per customer. The CML index is equivalent with the SAIDI index (given in hours), and the formula is given as [29]:

$$CML = \frac{The\ sum\ of\ the\ customer\ minutes\ lost\ for\ all\ restoration\ stages\ for\ all\ incident}{Total\ number\ of\ customers} \quad (2.14)$$

Another metric [29] to quantify the number of customers re-interrupted per 100 customers per year is:

$$RI = \frac{The\ sum\ of\ the\ number\ of\ customer\ re\text{-}interrupted}{Total\ number\ of\ customers} \cdot 100 \quad (2.15)$$

All of the previously presented reliability indices quantify the reliability performance in terms of long interruptions. For quantifying frequency of short interruptions of supply (which are not distinguished in terms of duration), the ***momentary average interruption frequency index, MAIFI***, is expressed as the average number of short interruptions per customer per year, calculated as:

$$MAIFI = \frac{Total\ number\ of\ customer\ momentary\ interruptions}{Total\ number\ of\ customer\ served} \quad (2.16)$$

The MAIFI index is used by several European DNOs (e.g. France, Italy, etc.), while in the UK, DNOs report short interruption (SI) index, which is similar to the MAIFI index. In some cases, the aggregation of SIs and LIs is performed when the separation periods between them are relatively short (less than 3 minutes). For example, if a customer experiences SI for 2 minutes and the supply is then restored back for 2 minutes, but then a long interruption occur for 30 minutes, after which the supply is restored permanently, this event will be categorised as a single long interruption of 34 minutes (the first restoration of 2 minutes is still counted as an interruption, as the separation of SI and LI is less than 3 minutes) [30]. For SI, in the case of multi-shot automatic reclosing schemes, multiple SIs are defined as a single SI, assuming that the supply is successfully restored within less than 3 minutes, regardless of the number of automatic reclosing operations resulting in SIs [30]. In this thesis, SIs are analysed as supply interruptions shorter than 3 minutes without considering minimum duration of SIs [5].

While previous reliability indices are basically defined as customer-oriented indices, ***average energy not supplied, AENS, and ENS*** are examples of energy-oriented indices. The AENS is expressed as energy (e.g. in kWh or MWh) not supplied per customer and per year and is calculated as:

$$AENS = \frac{Total\ energy\ not\ supplied}{Total\ number\ of\ customers\ served} \tag{2.17}$$

The ENS is calculated as the total energy not supplied for all interrupted customers, i.e. as AENS multiplied by the total number of served customers. Although there are further reliability indices, such as CAIFI, ASAI, etc., these are not presented and discussed, as they were not used to quantify the network reliability performance in this thesis.

2.3 Distributed Generation

Distributed generation (DG) generally denotes a small to medium-scale electricity generation connected to a distribution network, which is becoming increasingly important for the analysis of (distribution) network performance due to continuous growth of installed DG systems. Accordingly, this section defines the term "Distributed Generation (DG)" and gives an initial literature review of the impact and effects of integration of DG on the distribution network performances, which is later discussed in more detail in Chapter 6.

The International Energy Agency (IEA) defines DG as "a generating plant serving a customer on-site, or providing support to a distribution network, connected to the grid at the distribution level voltage" [31], while CIGRE defines it as "a generation with the following characteristics: it is not centrally planned and dispatched, and is usually connected to a distribution network with a small capacity of between 50–100 MW" [31]. The Electric Power Research Institute defines it as "a generation from a few kilowatts, up to 50 MW" [31].Often, the term DG is changed to microgeneration (MG), typically for generation systems at a domestic scale, where the capacities are less than 50 kW electrical, or 30 kW thermal [32] .

Input energy sources for DG can be fossil fuel (e.g. natural gas, or diesel), or renewable energy resources (e.g. solar or wind) and one of the reasons for the increased recent use of DG systems is utilisation of renewable energy resources (RER). In the past, however, the term DG was most often related to the backup or customer-owned generation for producing electrical and thermal energy for on-site use, typically by natural gas, coal and biomass-fired generation. Backup generators, which mostly use engines fuelled with diesel oil or gasoline, are commonly found in high-rise buildings, hospitals and industry, which depend on highly reliable supply of power. Small-scale RER-powered DG is mostly used in residential areas (as microgeneration systems), with most common technologies for grid-connected DG being wind turbines and solar photovoltaic (PV) systems. Although RER-powered DG has almost zero carbon dioxide emission, the output produced by the DG are variable and unpredictable, making it currently unable to be used as a fast response backup supply, or for supplying base system load.

2.3.1 Impact of Distributed Generation on Distribution Networks

Traditionally, distribution networks are designed and operated as passive systems, with tap-changing transformers in primary distribution substations and reactive power compensation (capacitor banks) being the only actively controlled elements, which are both typically used for voltage regulation in the networks and at some specific locations. Another important aspect of operation of traditional distribution networks is a unidirectional flow of powers, from the primary MV substations to the secondary MV/LV substations and final end-users, where networks are not intended to accommodate (any significant) active power generation, particularly if it may resulted in reversed, i.e. bi-directional power flows [33].

The increased penetration levels of DG in modern distribution networks require careful re-evaluation of basic principles of operation, protection and control, particularly in weak distribution networks. If the power output of DG is higher than demand of the loads supplied from the primary substations, this typically results in the increased voltage at the DG location due to reverse power flows [34]. Although it is possible for the tap-changer transformers to regulate the voltage in the downstream network, this situation requires coordination of network voltage control with the DG operation, which might be difficult when the location of the DG is in the middle of the feeder [35].

The distributed power reduces from the higher voltage levels (upper parts of the network) towards the lower voltage levels in the network (downstream parts of the network). Accordingly, the size and capacity of network components in the upper parts of the network are bigger and reduce along the feeders in the downstream network (manifested in, e.g. tapered cross-sections of conductors). If the DG system is designed to satisfy only local demand, it will reduce the power flows from the grid, i.e. thermal loading of network components from the downstream to the upstream of the network [36]. However, if the DG output is greater than the local demand, energy will be exported to the upstream network and excessive reverse power flow might lead to the increased thermal loading, as well as increased losses and the higher probability of faults, which will then result in supply interruptions of customers.

During the network design, the thermal capacity of network components is correlated with fault levels in the network, which are calculated at various locations in order to select adequate types and settings of protection devices. Before the implementation of the DG, the typical protection schemes are based on the existing operation of the network and coordination of the protection devices was based on unidirectional power flows, i.e. on the use of non-directional protection relays. After the implementation of the DG, the fault levels in the network will change and protection systems should be re-evaluated in terms of possible fault current contributions of the DG. In cases of reversed power flows, some of the existing protection devices (and their coordination) might need to be changed, e.g. by replacing non-directional with directional relays. For example, particularly challenging is operation of DG in so called “micro-grid” mode, when in the case of the upstream fault, resulting in the disconnection of the faulted part of the network, DG continues to supply local load (“islanded” operation). Stable and safe operation of the micro-grid part of the network in both grid-connected and off-grid operation modes will require different settings of protection devices (as fault levels will change), rearrangement of earthing conditions and careful coordination of the transfer switches. Adaptive protection schemes have been developed in order to improve the coordination of the protection devices, and one of the solutions is to divide the distribution networks into multiple smaller parts [37]. The fault location can be detected separately in each of the smaller parts by measuring the fault level contributions from the DG.

Most of the DG units are typically located near the consumption points, which is particularly true for the DG units that serve as a back-up supply. These DG units allow operation of a single building, or a single installation in “islanded mode”, in case of a fault in the upstream network, supplying all or part of the customers (e.g. emergency loads) in the otherwise disconnected building/installation and maintaining continuous power supply (from DG) and improved reliability levels [35, 38]. Since this type of DG does not start instantaneously, customers will experience short interruption during the transfer/switch to DG supply and some especially sensitive customers may utilize uninterruptable power supply (UPS) in conjunction with the DG during the transfer switch [35].

The DG units that normally operate in parallel with the utility source could improve the security and reliability levels of distribution networks to which they are connected, while reducing line losses. As long as the DG is connected and producing some outputs, it will result in reduced power demands from the network. The delivery of power to the network by the DG is recorded (and controlled) by the net metering, which is defined as exported DG power, whenever DG output exceeds the local load demand and results in power being fed back into the distribution network [35]. In these conditions, the DG is capable of supplying a portion of, or full load demand and reduced energy transfers through network components (e.g. cables, transformers, etc.) effectively reduce system active power (I^2R) losses [39], while also releasing network capacity. From the reliability point of view, however, reduced losses and thermal stress/loading of equipment result in the lower probability of equipment fault, and, when faults happen, in the higher capacities of healthy network components to supply demands (with loads reduced due to local DG generation).

2.3.2 Technical Requirements for DG Connection

Generally, the impact of the DG on network operation and changes in reliability performance will depend on the location, size and ways in which DG is controlled and operated. This is typically evaluated before the DG is connected, in the studies related to satisfying technical requirements for the grid connection of larger DG units, where the main concern is to demonstrate that after the DG connection there will be no degradation of the network performance, or that any possible negative impact of DG is within the specified limits. However, in case of microgeneration, i.e. when connected DG units are small (<50 kW), the requirement for DG owners and DNO to carry out detailed studies before connecting DG are less stringent – only general requirements should be satisfied, which are typically taken care of by the DG manufacturers and installers. In such cases, connection of a large number of small DG units might result in the impact of such aggregated DG on the network which is similar to the connection of larger DG units, but which is not evaluated in detail.

Connection of DG is also subject to further technical requirements and guidelines, which are issued by the specific DNOs and are different in different countries. In this thesis, the analysis of DG impact on network reliability performance assumes that all technical requirements, regulative and legislative documents for the DG connection in the UK are applicable. In the UK, the requirements for the connection of DG are provided by the Energy Networks Association (ENA) and categorised into three sections, based on voltage levels and DG rating. Each section provides a “route map” and guidelines for the installation of DG in the UK distribution networks:

- ER G83/2 – connecting DG of up to 16 A/phase in LV networks.
- ER G59/3 – connecting DG of up to 5 MW output below 20 kV.
- ER G75/1 – connecting DG with more than 5 MW output, or at voltage above 20 kV.

2.3.3 DG Network Integration

As previously mentioned, the existing distribution networks were designed for unidirectional power flows from the HV transmission system to the MV and LV distribution networks, where electricity is delivered to the customers. This typically resulted in predictable energy flows, which required low levels of monitoring, control and automation. Increasing numbers of DG in distribution networks impact changes in power flows and require further adjustment in network control, monitoring and communication systems, in order to support further connection of DG units and maintain existing or improve future security and reliability levels in the network.

Different DG network integration methodologies exist, with various requirements for advanced design, monitoring and coordination techniques, in order to ensure correct and optimal operation of both network and connected DG. Three general “levels of DG integration” are illustrated in Figure 2.4, where the evolution of the distribution networks with DG progresses from passive DG network integration, through reactive DG network integration, to active DG system management, based on the DG penetration levels [23].

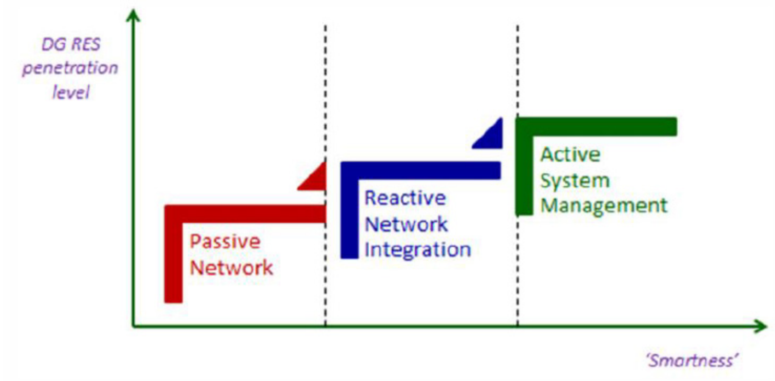


Figure 2.4: Evolution of DG connection and integration [17].

2.3.4 Passive DG Network Integration

According to the traditional philosophy of operating and controlling distribution networks, the passive network DG integration applies "fit-and-forget" approach for the connection of DG. In this approach, the DG units are considered as the "negative loads" and DNOs typically provide firm capacity connections, regardless of the network configuration, loading conditions and security requirements (e.g. the actual fault level contributions of DG).

This approach has the advantages of low monitoring, flexibility, control and supervision requirements for the network operation with DG. As the amount of connected DG is typically low, resulting in low or easily quantifiable impact, important aspects of network operation can be also easily re-adjusted after the DG is connected. For example, voltage regulation will be still performed by tap-changing transformers, which will be able to maintain voltages within the limit for all customers, including those at (most) remote network ends.

If the DG in the considered distribution network continues to further increase, significant investments will be required to continue to operate the network in the same way, with the same configuration and without coordination with the DG (e.g. without installing new transformers, new feeder lines and applying other similar network upgrading/reinforcing measures), which, when applied, will make this approach for managing networks with DG less economical and, therefore, less practical.

2.3.5 Reactive DG Network Integration

Once the DG penetration increases and results in inability to accommodate further DG units on a premise of firm capacity connection (so called "sterilised" network), the DG will start to strongly impact network operation. In this case, the specific operational constraints should be evaluated for coincidental conditions of high DG outputs and low loading conditions. In case of renewable-based DG, where the variability of input energy sources results in the variations of DG outputs, the violation of network constraints (e.g. excessive voltage variations, or thermal overloading of components) may occur only during a short period of time (typically few/several tens of hours per year). Accordingly, the "fit-and-forget" approach might be still implemented, like in the earlier stages of the DG development and installation, assuming that the excessive DG outputs are limited or curtailed, or that the DG will start participating in the network control, by, e.g., changing operational power factors, or that additional coordination or regulation devices are implemented to address the possible negative DG impact (e.g. installation of dedicated energy storage system, or demand-side manageable loads, or volt-var regulation equipment).

The above approach is termed as "reactive DG network integration" and is often characterised by the specific operating conditions. Installation of new DG units is still encouraged, assuming that the operational constraints and restrictions (e.g. congestions and overloadings) are resolved by controlling, coordinating or restricting DG outputs and/or loads. The control of DG under the reactive integration is more manageable and flexible than under the passive integration, but inability of DNOs to plan and control the process of DG deployment will again result in the "sterilisation" of certain portions of the network for the further DG connections. Generally, it is very difficult to optimally place DG in the network, as DG locations are determined by the DG developers with specific land and resource availabilities.

2.3.6 Active DG Network Integration

The passive network integration is an approach where connecting of the DG was not considered in depth at both planning and operational stages. The reactive network

DG integration approach neglects the DG at a planning stage, but aims to fully or partially resolve the problems due to DG connection during the operational stage. The active network DG integration approach incorporates DG connection considerations at both planning and operational stages, allowing to perform overall optimisation of the distribution network design to accommodate high DG penetration levels, while deferring network upgrades. Compared to the two previous approaches, the active integration approach allows DG developers and DNOs to resolve all possible conflicts of interest and to find the most cost-effective solutions that will maximise benefits to all involved parties.

The realisation of active network DG integration approaches is a challenging topic, which is still in the development. It generally requires detailed and comprehensive studies at the planning stage, involving complex and large sets of input data and parameters, which should be implemented in flexible ways at the operational stage. The focus of this approach is primarily on the planning stage, in order to maximise the DG penetration levels (so called "hosting network capacity"), while maintaining, or even improving, the security, reliability and stability of distribution network.

2.4 Chapter Summary

This chapter presented and discussed some basic aspects of the operation of power supply system and its three basic parts (generation, transmission and distribution) in relation to the assessment of reliability performance. The evolution of traditional reliability concepts is briefly reviewed, as well as the theoretical background for reliability assessment based on the relevant literature. The most commonly used reliability concepts, metrics and indicators are presented, including comparison of the UK practices with approaches in Europe and other countries (US/Canada) .The term "Distributed Generation (DG)" is defined and an initial discussion of the impact and effects of integration of DG on the distribution network performances is presented regarding three general levels of DG integration.

Chapter 3 Reliability Assessment Techniques

This chapter presents the basic aspects of the two main techniques used in this thesis for the calculation of the system and customer-based reliability indices: a) analytical reliability assessment approaches (i.e. failure modes and effects analysis), and b) probabilistic reliability assessment approaches (i.e. Monte-Carlo simulations).

Analytical approaches generally limit output results (i.e. calculated reliability indices) to only the mean values, while probabilistic approaches provide a more comprehensive information, including probability distribution functions, standard deviations and variations of the calculated reliability indices. Analytical approaches always produce one single set of output results for one single set of input parameters, while probabilistic approaches always produce results which vary in certain ranges, based on the modelling of the related random and stochastic factors (e.g. assumed probability distribution of input parameters). Since probabilistic approaches give results with certain variations, the probabilistic reliability assessment process should be repeated until the (estimated) accuracy of the results is achieved. For that purpose, error coefficients are used to indicate when the calculation process should stop, after some convergence criterion is satisfied.

As mentioned, the concepts and methods for reliability assessment have evolved over the past decades from analysing the ability of individual components to operate without faults and as intended during their lifetime, into the comprehensive approaches for evaluating various engineering strategies for system planning, operation and maintenance studies. The conventional reliability assessment procedures now receive different perspectives in different engineering applications, where of particular importance is evaluation of the risks of not satisfying specified targets imposed to the DNOs by the Regulators, as this will typically result in penalties. This aspect of reliability analysis did not receive much attention in existing literature and is, therefore, discussed and further illustrated with the results calculated by probabilistic approaches (which are inherently suited for risk-based analysis) in Chapter 6.

The reliability analysis of modern networks is typically aimed at assessing the whole-system reliability (i.e. not individual components), and is therefore involved with the analysis of large, complex, and highly-integrated networks. This results in significant computational requirements and simulation times and (very) large sets and databases of output results, which introduce additionally difficulties for analysing, post-processing and interpreting. Consequently, the reliability analysis of modern interconnected power supply systems is almost always divided into three previously discussed segments: generation, transmission, and distribution.

For example, [40, 41, 42] discuss the reliability assessment on these three corresponding hierarchical levels, where particularly analysis of MV distribution network level requires modelling of a large number of network components and analysing the multitude of ways in which these components are inter-related during the assessment. When reliability analysis of distribution system level includes all LV networks supplying individual LV customers, the modelling and computational requirements might prohibit the direct application of the conventional reliability approaches. This is further discussed in Chapter 4, where simple yet accurate reliability equivalents of generic LV networks are introduced for the analysis.

Another important aspect of the reliability analysis of modern (and future) electricity supply networks is that some of the functionalities that were previously implemented only at the higher voltage levels (i.e. in transmission networks) are becoming increasingly present in distribution networks. Examples include automation, reconfiguration and remote control functionalities, as well as presence of alternative supply points and operation in (normally open) meshed configurations. In other words, more complex operation schemes and more advanced components are being installed in distribution networks, in order to reduce the number and duration of supply interruptions and allow DNOs to achieve higher reliability performance levels. For example, a standard fuse, which is the most common protection element in LV networks, is recently being replaced by a so called “smart fuse” [43], or by a standard circuit breaker with automatic reclosing or remote control functionalities.

These and other “smart grid” functionalities should be remodelled in the conventional approaches, in order to properly assess the changes in the reliability performance.

The main advantages and disadvantages of analytical and probabilistic approaches for reliability assessment can be summarised as follows:

- Analytical approaches generally have reduced ability to correctly model specific network or component functionalities. An example is modelling of the alternative supply point, which does not “operate” in the analytical approach, but just changes the supply restoration times (i.e. repair times of the corresponding faulted components are not used) to the time required for the transfer to alternative supply points. Probabilistic approaches, on the other hand, can model transfer to alternative supply points in terms of its actual operation, reflecting general ability of probabilistic approaches to model or reproduce relevant characteristics and functionalities in the analysed network.
- Computational times for the analytical reliability approaches are much shorter than for the probabilistic approaches, particularly if modelled networks are complex/large and if long simulation periods are required for correct assessment.
- The analytical approaches provide the same set of output results (average values of reliability indicators) for the same network model (configuration and operating/loading conditions) and same input parameters, while probabilistic approaches provide different and more detailed results (distributions of reliability indicators), depending on the assumed probability distributions of input data, criteria for convergence and accuracy.

3.1 Analytical Reliability Assessment Approaches

Analytical reliability assessment approaches are often used for network planning or system security studies (e.g. N-1, or N-2 security criteria), as well as for evaluating network contingencies and system capacity, or reserve requirements. Essentially, the analytical approaches cannot model the inherently stochastic nature of occurrence of system faults, or significant variations in the fault repair times, or equally wide ranges of changes in system operating conditions and customer loading conditions.

Analytical reliability assessment approaches are based on the suitably formulated mathematical models of healthy vs. faulty system components, which characterize analysed network in terms of the specified input data, typically limiting output results to mean/average values of reliability indices, corresponding to specified input mean/average fault rate and repair time data. This is considered as one of the main limitations of analytical approaches, as they offer only a general "snapshot" characterisation of the analysed system and should be repeated whenever any input data or parameter changes.

In order to resolve this problem, this thesis offers a simple modification of the analytical reliability approaches, where only a limited set of carefully identified typical or characteristic loading and operating conditions are selected and inputted into the analytical approach, resulting in an estimation of the range of analytically calculated reliability indices [44, 45]. In that way, the analytically calculated ranges of values not only provide a more comprehensive information on possible changes of system reliability performance, but can also be directly compared with the corresponding results of the probabilistic approaches.

3.2 Probabilistic Reliability Assessment Approaches

Probabilistic reliability assessment procedures are widely recognized as more suitable for the analysis of reliability performance of modern power supply systems, particularly in terms of their ability to model stochastic and inherently unpredictable occurrence of system faults and component failures, which can be effectively represented through the variations of input parameters and data (e.g. fault rates and repair times of network components) with their assumed probability distributions. However, although the probabilistic approaches are capable of including in the model stochastic/random nature of the modelled processes, exactly this aspect of probabilistic approaches opens an important question of the accuracy or error of the calculation. In this context, probabilistic approaches can be divided into two general categories:

1. Approaches without explicit accuracy or error estimation (e.g. by using an independent convergence criteria, or error coefficient) in calculation procedure. In this case, the mean values of the calculated reliability indices are different from these calculated by analytical approaches.
2. Approaches with inclusion of accuracy or error estimation, when the results calculated by probabilistic approaches are typically close to the mean values from analytical approaches (the difference can be treated as an error).

Importantly, the probabilistic assessment approaches are able to model a wide range of variations of practically all input parameters and data in one, or only a few simulation/calculation set-ups, without the need to restart or repeat the calculation after a change of input data. Furthermore, probabilistic analysis can be performed “sequentially”, by following the chronological or time-sequence transitions of network components from one state to another (i.e. between "normal/healthy operation" states and "faulty" states) and/or by following stipulated chronological changes in the system loading conditions (daily, weekly and seasonal). Non-sequential (or random) probabilistic approaches consider the time as an independent variable and neglect the transitions between the different states of the system. With both probabilistic approaches, obtained probability distributions of calculated reliability indices allow to study in more detail the behaviour of the network components and the network as a whole. A clearer picture of the possible range of variations of performance indicators also allows to study in more detail the impact of each new applied functionality, or of installing a new component, or of upgrading the network, which is crucial for identifying the most cost-effective actions and measures for the improvement of network reliability performance.

3.3 Analytical Reliability Assessment in this Thesis

Several analytical reliability assessments procedures have been reported in the literature for the evaluation of power system performance [11, 12, 25]. Before performing the reliability assessment, consideration should be given to the types of protection devices in the analysed network. A fuse or a circuit breaker will isolate the fault under on-load conditions, or in system energized state (fuses are single-pole devices, while circuit breakers are three-pole devices). On the other hand, a disconnector or recloser will first require the circuit breaker to de-energize the faulted component, or faulted part of the system, before it can operate, due to the limited fault-interrupting capabilities.

The information on the used types (and settings) of protection systems is important for distinguishing between LIs and SIs, i.e. for correctly assessing the duration of supply interruptions experienced by the customers. Similarly, it is important to know whether the transfer to alternative supply point is performed manually or automatically (i.e. manual vs. automatic or remotely controlled switches) as this, too, will have an impact on the duration of supply interruptions.

The most common techniques for analytical reliability performance evaluation are: state-space diagram (Markov model), approximate method, network reduction method and failure modes and effects analysis (FMEA). The Markov model identifies the possible states of the considered system and components, possible transition paths between these states, and rate parameters of the transitions. During the analysis, the transitions are usually formulated in terms of components' fault rates and repair times. For a single component, a simple two-state model can be defined as component being available (i.e. "healthy" and in normal operation) and component being unavailable (i.e. "faulty", or out of operation). Although this method is accurate, as the number of components grows for the analysis of large networks, the calculation might become too complicated, or even infeasible.

Approximate and network reduction methods are closely related. The approximate method generally has two basic equations for the equivalent representation of system components, either in series, or in parallel connection/configuration, for which equivalent fault rates, repair times and unavailability are calculated. Similarly, the network reduction method creates a sequence of equivalent components obtained from combining series- and parallel-connected components.

The FMEA method is related to the evaluation and application of the minimal cut set method, which is defined as a particular sub-set of all network components for which failure/fault of any single component from this set will cause failure, or prevent normal operation of all components connected/related to this faulted component. This is done in order to identify all components that impact interruption (both LIs and SIs) of specific customers.

In this thesis, the FMEA method is used as the analytical approach for the reliability performance assessment of the considered LV and MV distribution networks. The analytical approach does not require simulation of a certain number of years, as the output results correspond directly to the network configuration and specified input data, and do not change from one year to another. The main steps of the analytical approach used in this thesis are shown in detail in Figure 3.1.

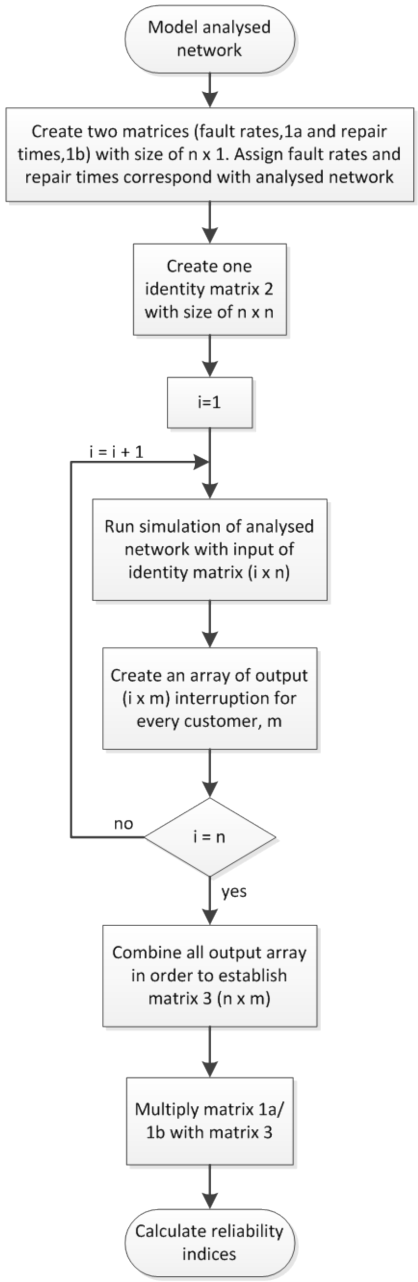


Figure 3.1: Algorithm for the implementation of the analytical reliability assessment procedure

The main steps of the algorithm can be summarised as follows;

1. Model (create the model) of the analysed network (e.g. in PSS/E software).
2. Create two vector-matrices (n x 1) with size of all power components, n. Assign fault rates (**matrix 1a**) and repair times, or protection times, or times

to operate alternative supply (**matrix 1b**), to all network components corresponding to the model of the analysed network.

3. Create an identity matrix (**matrix 2**) with size of all power components (n x n). For each column, the single '1' value denotes the fault of the certain component.
4. Run simulations based on input '1' (forced fault on component) and '0' (no fault on the component). In each simulation step, only one component is faulty (starting from the first column of **matrix 2**), and simulations continue by taking components from the subsequent columns of the matrix, until the last column/component is reached.
5. For every simulation step/component, create an array (1 x m) indicating for each load point/customer, m, if there is supply interruption ('1') or no interruption ('0'), for the currently faulted component. Combine all output arrays in order to establish **matrix 3** (n x m), specifying interrupted customers for each faulted component.
6. Multiply array of fault rates of components with array of customer interruption to establish SAIFI index. Multiply array of fault rates and repair times with array of customer interruption to produce SAIDI index. Lastly, multiply repair times and array of customer interruptions to calculate CAIDI index.

3.4 Probabilistic Reliability Assessment in this Thesis

The probabilistic techniques have been widely recognised as suitable for the analysis of power system reliability performance, due to their capability to provide comprehensive results and possibility to estimate changes and variations in the network reliability performance. The most common probabilistic reliability assessment approach is the Inverse Transform Method, also known as the Monte-Carlo Simulation (MCS) procedure.

The two main variants of the MCS method are: non-sequential (random) and sequential simulations. The non-sequential MCS technique simulates the transitions between the states of the considered components (over their lifetime) randomly and considers the time as an independent variable. In order to have statistically reliable (accurate) calculated values (e.g. average values of reliability indices), the simulations are repeated a great number of times (for the specified service period). On the other hand, the sequential MCS is characterised by chronological or time-sequential transition of component states, where component transfer from, e.g. normal operation state to faulted state and, after repair time has passed, back to the normal operation state. Similarly, sequential MCS simulations are also reproduced/repeated many times over the assumed period of service to obtain statically reliable output results.

In this thesis, sequential MCS is applied for the reliability analysis. The basic aspect of the MCS technique is the use of random, or pseudo-random numbers. The random numbers required for the assessment of, e.g. fault probabilities of components, are generated in a uniformly stochastic distributed way in the range [0, 1], independently for each components, therefore correctly representing or mimicking true random behaviour of the modelled components and processes in which components are involved. The operating and failure states of each network component are obtained through the combination of input reliability data (i.e. mean fault rates and mean repair times) with the allocated (i.e. assumed or known) probability distribution functions (e.g. Exponential, Weibull, Rayleigh, Normal, etc.). The generated random numbers are assigned to an inverse distribution function, in order to convert the network components' mean fault rates (λ) and mean repair times (i.e. "mean time to repair", MTTR) into the corresponding operating and failure states of each network component (i.e. "time to fail", TTF, and "time to repair", TTR, Chapter 2).

The mean fault rates of network components are typically given in "faults per year" and the minimum period of simulation is at least one year. Although it is possible to perform the simulation with the maximum period of a lifetime (i.e. 40 years) of an average network component, sometimes that time period is not sufficient due to the low values of component's mean fault rates. Accordingly, the adequate minimum time period for simulations will depend on the minimum value of all components' fault rates. For example, for a component with a mean fault rate of 0.0001 fault/year (corresponding to one component experiencing a fault in a system in which 10,000 components are installed in one year), simulation time period of 1,000 years will result in around 0.1 fault of this component, while a change of the time period of simulation to 10,000 years will allow to have at least one fault of this component in the modelled network (assuming no more than one such component is present in the network model). However, increasing the time period of simulations will also result in (much) longer computational times.

The main steps of the MCS probabilistic approach used in this thesis for the reliability assessment of considered networks are shown in Figure 3.2 (algorithm) and can be summarised as follows;

1. Model (create the model) of the analysed network (e.g. in PSS/E software).
2. Assign mean fault rates and mean repair times (or protection times, or times to operate alternative supply) to all network components from the model of the analysed network.
3. Establish type of the probability density function to model initial conditions for all components' fault rates and repair times.
4. Generate random numbers for all network components in the network and convert them in times of fault (the start time of each fault), based on the values of the corresponding fault rates.
5. For each faulty component, generate random number and convert it to period of fault (duration of each fault), based on the corresponding repair time. Associate each period of fault with start time of the fault.
6. Run power flow algorithm after the fault of each component. In this thesis, a steady state analysis with balanced power flow solver, using the standard Newton-Raphson iterative method with the PSSE software package.
7. Count every supply interruption for each customer (i.e. how many customers are interrupted for each fault).

8. Calculate the duration of each supply interruption.
9. Compute reliability indices (e.g. SAIFI, SAIDI, CAIDI, ENS, etc.).
10. Estimate the error/accuracy (e.g. by checking the average values of calculated reliability indicators with some analytical approach, or use other criteria).

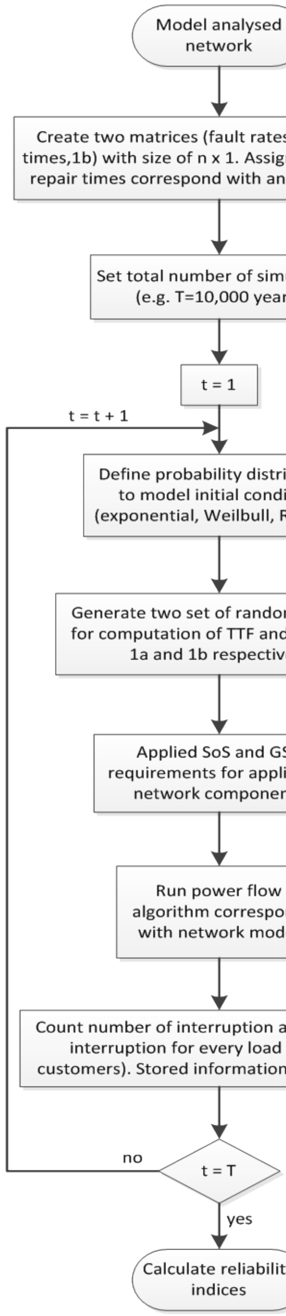


Figure 3.2: Algorithm for the implementation of the probabilistic reliability assessment procedure (MCS).

3.4.1 Classification of Long and Short Customer Interruptions

An important aspect of reliability analysis is correct distinction between long and short supply interruptions. For example, faults of some network components are often temporary, i.e. not permanent, which is perhaps best illustrated with the faults on bare overhead conductors (animal and branch contacts, swinging wires due to strong wind, lightning, etc.), typically resulting in only short supply interruptions. Furthermore, there are various instances when permanent faults of network components do not result in long interruptions (LIs) of customers, e.g. in case of previously discussed transfer to alternative supply points, when again only short interruptions (SIs) are experienced by customers.

In this thesis, evaluation of numbers of SIs and LIs is performed by analysing the available network statistics from the DNOs and linking it to the applied reliability assessment procedure. Based on the OFGEM statistics from 14 UK DNOs for the year 2009, it is estimated that 46% of supply interruption events were caused by permanent faults (i.e. LIs) and 54% by momentary/transient faults (i.e. SIs). However, although this statistics allows to evaluate contributions of both types of interruptions to the overall network performance, the provided information is general, i.e. related to all of the UK distribution networks, without specifying how the numbers change in different areas/types of the networks, e.g. in urban areas (characterised by underground cable networks) and in rural areas (characterised by overhead line networks). Therefore, an extensive review of available literature is performed in order to specify variations in LV and MV distribution networks in highly-urban (HU), urban (U), sub-urban (SU) and rural (R) areas. This is shown in Table 3.1, which presents the reported statistical data for percentage contributions of both long and short supply interruptions in these four main areas/types of the LV and MV distribution networks. The results for the DNOs in France and Italy are used for further analysis, while statistics from Finland are not taken into account due to much larger variations compared to others statistics (attributed to much longer length of LV and MV networks and much lower number of customers). Furthermore, the values for highly-urban (HU) areas (which are not reported in original sources) are assumed to be the highest value of reported values for urban (U) areas.

Table 3.1: Percentage contributions of long and short supply interruptions.

LI/SI Ratio	Voltage level	Finland [46]	France[14]	Italy[14]	Average
LI	MV/LV	U=87 SU=81 R=78	U=48 SU=34 R=23	U=40 SU=28 R=25	HU=48 U=44 SU=31 R=24
SI	MV/LV	U=13 SU=19 R=22	U=52 SU=66 R=77	U=60 SU=72 R=75	HU=52 U=56 SU=69 R=76

Based on the statistics in Table 3.1, it can be seen that the number of SIs (and their percentage contributions to all supply interruptions of customers) are increasing from highly-urban, through urban and sub-urban, to rural areas, while the opposite is true for LIs. The main reasons for these changes are types of components and installations (underground cables vs. overhead lines, open vs. closed substations, manual vs. automatic control and protection, etc.), which directly reflect the impact of the exposure to weather conditions, external factors and required supply restoration times. The demand densities and numbers of served customers also differ from highly populated urban areas to sparsely populated rural areas, impacting, for example, available space for network components and transfer from overhead-line networks (rural areas) to underground-cable networks (urban areas).

As mentioned, the analysis becomes rather complex when modelled networks can be reconfigured during the fault and when alternative supply points (with limited or restricted capacities) are available. This requires to make further distinction between activation of protection systems (clearing the faults), automatic/manual switching for reconfiguration and transfer to alternative supply (within or outwith the 3-minute limit between SIs and LIs) and repair times of faulted components in determining both frequency and duration of customers' supply interruptions. In other words, faults might not be directly associated with the LIs based on the MTTR values (see for example Table 5.2 in Chapter 5), but might result in only SIs, regardless of the actual (or reported) values of MTTR required for the repair of faulted components.

3.4.2 Correlation of Long and Short Interruptions with Actual Load Profiles

Traditionally, for both analytical and MCS reliability assessment approaches, the supplied loads are usually represented by a bulk/lumped model, specifying rated or maximum power demands. This basically corresponds to the "worst case" scenario, as the analysis of faults will then result in the interruption of the maximum number of customers, i.e. in the maximum load/energy not supplied. However, for most of the time, the actual customer demands are lower than the maximum one, and this approach for reliability performance assessment typically (significantly) overestimates calculated reliability indices, i.e. results in lower than actual reliability performance levels. By incorporating actual time-variable load demands, only a part of customers, or possibly no customer will be disconnected. Moreover, a better correlation between the time at which faults occur in the network and the time-dependent changes of actual demands (represented by e.g. load profiles/curves) will significantly improve calculation of reliability indices, as the higher fault rates should be allocated to the periods of time when demand (and therefore loading conditions of network components) are higher, than when the demands are lower (e.g. during the night). This is discussed in the further text.

In order to satisfy peak demand, a 33 kV grid supply point (GSP), which is a primary distribution substation, is typically supplied by two identical parallel transformers, each with a lower rated power than the peak demand (normally 60-70% of the peak demand) due to the lower capital and maintenance costs, compared to installing two transformers rated at 100% of the peak demand. If one of the transformers is faulty, or disconnected for a maintenance, the other transformer will still be able to supply customers, as long as the load demand is below the transformer's rated capacity. Although each transformer is capable to operate with a higher than rated capacity (e.g. 120%-150%) for a limited time (minutes to hours), this is unfavourable, as it will lower the expected lifetime of the transformer.

Figure 3.3 illustrates the significance of accurate evaluation of the time at which a fault occurs, as otherwise the results for reliability indices will be underestimated or overestimated. All customers will still receive continuous supply demand (i.e. there will be no customer interruption) when one of the transformers is out of operation for the period of time for which load demand (black solid line) is lower than rated power of a single transformer (black dashed line), which is between 23:30 hours and 07:00 hours for the presented load profile. Figure 3.3 also shows how probability of a fault of the transformer changes during the 24-hour period, which then allows to directly correlate and incorporate daily load profiles and daily fault probabilities into a more accurate sequential MCS analysis.

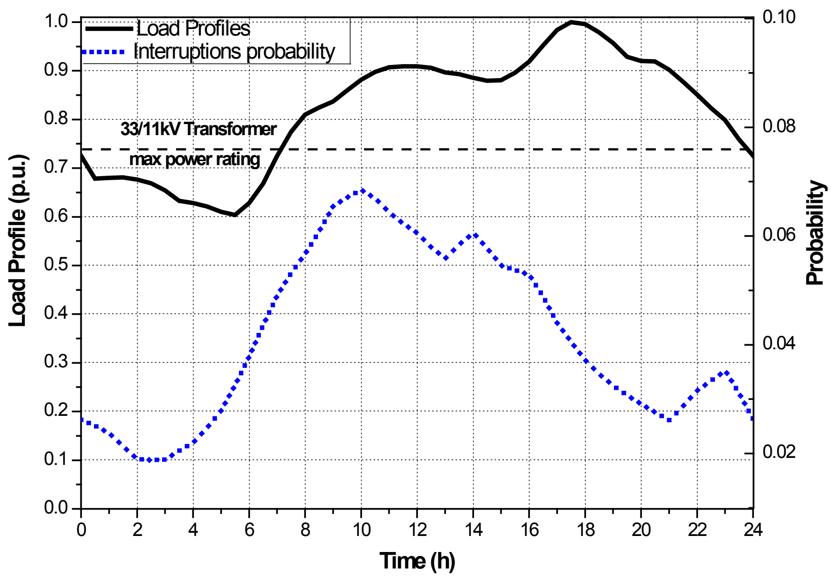


Figure 3.3: Correlation of daily load profile and daily fault probability

The daily fault probabilities used in this thesis are obtained from a detailed investigation of available statistical data, i.e. two years of recordings of all SIs and LIs for one UK DNO [4, 47], shown in more detail in Figure 3.4. This analysis allowed to define "empirical time-distribution for the probability of faults" in the analysis of the considered LV and MV distribution networks.

The daily probability profiles of the LIs and SIs are first represented with the theoretical interruption probability model (dashed green line) in Figure 3.4, using the formula in (3.1), and then were used to estimate daily variations in reported statistics for mean fault rates of the power components. The theoretical curve is divided into seven zones, with each zone covering certain period time in hours.

$$\lambda(t) = \begin{cases} \lambda_{mean} \cdot (-0.00248t + 0.02621), & 0 \le t \le 3 \\ \lambda_{mean} \cdot (0.0071t - 0.00251), & 3 < t \le 10 \\ \lambda_{mean} \cdot (-0.0042t + 0.1105), & 10 < t \le 13 \\ \lambda_{mean} \cdot (0.0559), & 13 < t \le 15 \\ \lambda_{mean} \cdot (-0.00497t + 0.13047), & 15 < t \le 21 \\ \lambda_{mean} \cdot (0.00457t - 0.06987), & 21 < t \le 23 \\ \lambda_{mean} \cdot (-0.00903 + 0.24293), & 23 < t < 24 \end{cases} \tag{3.1}$$

where: t is the hour of the day.

The aggregate daily load profiles (100% of demand) are recorded from the actual annual demands at a 33 kV GSP of the same DNO, which represent average daily contribution of 36.7% residential, 29.9% commercial and 33.4% industrial customers. It can be seen from Figures 3.3 and 3.4 that there is a close correlation between LI/SI probability distributions and daily load profiles, confirming a higher probability of LI and SI when load demands are higher, particularly during the hours of the morning peak demand.

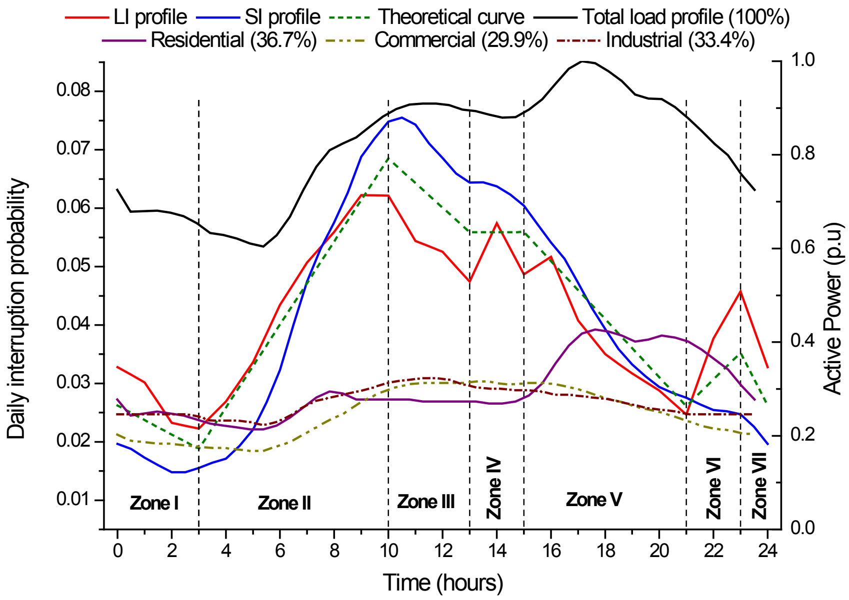


Figure 3.4: Load profiles and LI/SI daily probabilities used in this thesis.

3.4.3 Probability Distributions of Input Reliability Data

For analytical reliability assessment approaches, it is not possible to (directly) incorporate probability distribution function (PDF) of mean fault rates and mean repair times as the basic input data. On the other hand, MCS approaches explicitly assume that the input data vary with certain probability distributions, in order to evaluate how target reliability indicators might change (ranges of changes) during the total simulation period, divided in annual intervals with different input data.

The initial conditions of components' mean fault rates (λ) and mean repair times (i.e. MTTR) are in this section modelled with different PDFs, in order to investigate how the calculated reliability indicators change for different PDFs. Several previous references (e.g. [48, 49, 50]) suggest to use exponential distribution to convert random numbers into 'time to fail' (TTF) and 'time to repair' (TTR) values for power components, but for comparison purposes, the Weibull and Rayleigh distributions are also included in this section. The assessment of input probability distributions has been also discussed in [5], indicating error coefficients for the calculated mean values of the output probability distribution functions.

The coefficient of error for mean values is different from the coefficient of variation. For example, if the input mean repair time is 100 hours and after inverse transformation method (e.g. inverse PDF), a data set of outputs of: 90, 100 and 110 hours of repair times is obtained, the mean value will be 100 hours (i.e. mean value is preserved) and standard deviation will be 8.165 hours.

$$Coefficient\ of\ error = \frac{|input\ data - mean\ values|}{input\ data} x100\% \tag{3.2}$$

$$Coefficient\ of\ error = \frac{0}{100} x100\% = 0\%$$

$$Coefficient\ of\ variation = \frac{standard\ deviation}{mean\ values} x100\% \tag{3.3}$$

$$Coefficient\ of\ variation = \frac{8.165}{100} x100\% = 8.165\%$$

The above example shows a relatively large difference between the two coefficients, where (3.2) measures the error of mean value, or in other words, the efficiency of calculating mean value against the input data, while (3.3) measures the variation of the calculated data. Thus, for the purpose of assessing the accuracy of the output results in this thesis, the assessment of input probability distributions is included with the coefficient of error, with (3.4), (3.5) and (3.6) providing general characteristics of the three considered PDFs for the calculation of the TTF and TTR values.

$$Exponential: TTF\ or\ TTR = inverse\{1 - \exp(-\lambda t)\} \tag{3.4}$$

$$Weibull: TTF\ or\ TTR = inverse\{1 - \exp\left(-\frac{t}{\delta}\right)^{\beta}\} \tag{3.5}$$

$$Rayleigh: TTF\ or\ TTR = inverse\{1 - \exp(-0.5(\frac{t}{\sigma})^{\beta})\} \tag{3.6}$$

The initial calculation step requires the selection of a power component for calculating the initial condition (i.e. TTF or TTR). In this case, from Table 5.1 in Chapter 5, the selected power component is 0.4 kV busbar, with mean values of 0.005 faults per year and 4 hours of repair time per fault. Fault rates are modelled with exponential distribution for all cases, while the input values for the repair times are modelled with the three probability distributions (PDFs), giving the corresponding durations of LIs with a simulation period of 10,000 years. The reason for applying the simulation period of 10,000 years is due to the coefficient of error, which will be explained later in this section.

Furthermore, in order to directly compare the output results for the calculated MTTR values (i.e. durations of LIs) with different considered PDFs, the output fault rates must be maintained the same, or as close as possible. For this example, the input fault rate of 0.005 faults per year results in 49 faults (λ_output=0.0049, with error coefficient of 2%) within 10,000 years.

Figure 3.5 illustrates the results of the analysis for faults of 0.4kV busbars, corresponding to repair times modelled through the inverse transformation method with Exponential, Weibull (β = 6), and Rayleigh (β = 2) PDFs. Although the curves in Figure 3.5 are not smooth, due to a lower number of plotted points, all curves clearly follow the initially assumed PDFs. Table 3.2 shows the numerical results for the calculated output parameters for different selected PDFs, with comparison of mean, minimum, maximum, standard deviation, error coefficient and variation coefficient values.

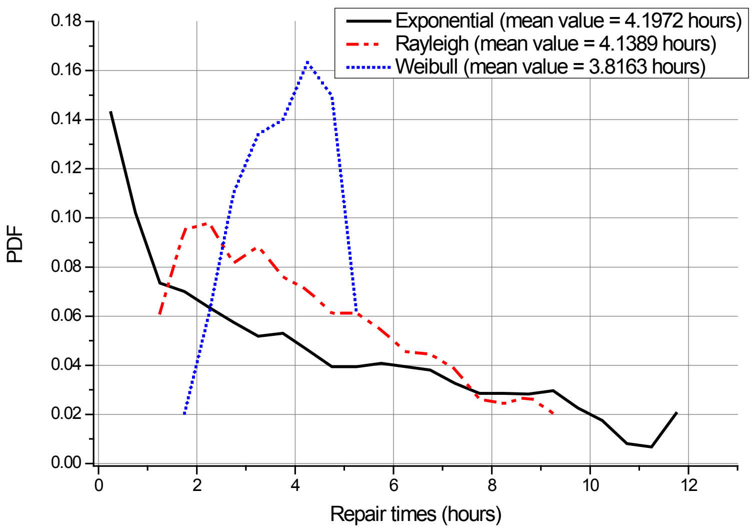


Figure 3.5: PDFs for MTTR of 4 hours (for 0.4kV busbar)

Table 3.2: Comparison of output MTTR result parameters for different PDFs.

PDFs	Mean value	Minimum value	Maximum value	Standard Deviation	Error Coefficient	Variation Coefficient
	hours				percent (%)	
Exponential	4.1972	0.0947	11.6177	3.2602	4.93	77.68
Rayleigh	4.1389	1.2094	9.0308	2.1302	3.47	51.47
Weibull	3.8163	1.5957	5.2530	0.8067	4.59	21.14

According to Figure 3.5 and Table 3.2, there are noticeable differences between the three sets of results. Although each PDF for input data resulted in error coefficient lower than 5%, mean values of exponential distribution are with the biggest difference from the input mean repair times (4 hours) and have the highest standard deviation (due to a long 'tail' of curve). On the other hand, Weibull distribution provides the lowest variation coefficient, but fully neglects the possible longer repair times, as there is no tail in the corresponding curve in Figure 3.5. This is important, as in practice there might be situations of occasional but long TTRs, as well as the situations resulting in much shorter TTRs.

The analysis in this section shows that there are no clear conditions for eliminating any of three considered PDFs from general reliability analysis. Based on the results in Table 3.2, all PDFs give an error coefficient lower than 5% (which is less than a typical tolerance for the duration of interruptions of 12% in [23, 51]). In addition, several studies implemented both exponential distribution [48, 49, 50] for TTF (fault rates values) and Rayleigh distribution (special case of Weibull distribution) for TTR/MTTR [23].

3.4.4 Total Simulation Times and Accuracy

As mentioned, the required MCS computational times depend on a number of parameters and factors, such as the size of the analysed network, the time-step of the simulations, the specified error or accuracy and the total duration of the simulated periods (e.g. 1,000 years or 10,000 years). However, the total simulated time will also impact the accuracy of the output reliability indices calculated by MCS approaches. This is illustrated further on an example of a 33 kV circuit breaker, with a mean fault rate of 0.0041 faults/year and mean repair time of 96 hours. Table 3.3 shows the output results and error coefficients for repair time of 96 hours, when different total durations of simulation (expressed in years) are used.

Table 3.3: Comparison of output results for repair times by different total simulation times

Year of Simulation	1,000 years		10,000 years	
	Output repair time (hours/fault)	Error coefficient (%)	Output repair time (hours/fault)	Error coefficient (%)
Set 1	93.3888	2.72	95.5723	0.45
Set 2	98.6803	2.79	97.1156	1.16
Set 3	93.2349	2.88	96.8885	0.93
Set 4	98.7151	2.83	96.5276	0.55
Set 5	97.6190	1.69	96.7359	0.77

As illustrated in Table 3.3, even though the effects of the random variations of repair times for a single component between the two total simulation periods are different, a 1,000 years of simulation has higher error coefficients than the simulations with a total period of 10,000 years. This effect of higher error coefficients becomes more pronounced and more visible, i.e. results in the cumulative effects, during the analysis in which a large number of network components is equivalented or aggregated.

Another important difference between the two sets of results for the two total simulation periods can be seen if the distributions of the TTR are plotted, Figure 3.6. Figure 3.6 presents two different curves of the probability distributions for two periods of simulations. Even though the error coefficients for the two periods of simulations are relatively small (less than 5%), the 10,000-year-simulation curve shows the more realistic values than the 1,000-year-simulation curve. This is expected, as the simulation period of 10,000 years resulted in around 40 faults of the component, as compared to around 4 faults for the simulation period of 1,000 years.

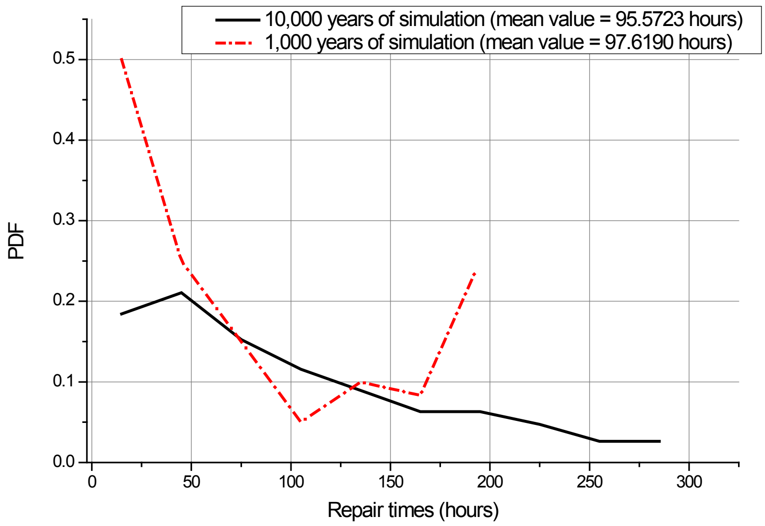


Figure 3.6: Variation between distribution curves for two periods of simulation

Finally, it should be noted that it is possible for repair time to achieve lower errors, as the non-integer output results simply transfer to a fraction of an hour (decimal points can be expressed in minutes, or even seconds). However, this is not the case for the fault rate results, which can have only integer number of faults per-year. For example, a single power component can possibly have 1 or 2 faults in a year, not 1.65 faults in a year. For that purpose, the following analysis will again consider 0.4 kV busbars, with a mean fault rate of 0.005 and mean repair time of 4 hours.

Table 3.4 shows the comparison of the calculated output parameters for the fault rates by the two different periods of simulation (1,000 and 10,000 years).

Table 3.4: Comparison of output results for simulated fault rates by two different total simulation periods

Year of Simulation	1,000 years		10,000 years	
	Output fault rates (fault/year)	Error coefficient (%)	Output fault rates (fault/year)	Error coefficient (%)
Set 1	0.006	20	0.0049	2
Set 2	0.006	20	0.0051	2
Set 3	0.005	0	0.0052	4
Set 4	0.004	20	0.0051	2
Set 5	0.006	20	0.0050	0

The first MCS period of 1,000 years can generate 4, 5, or 6 faults of the considered component. Although the fluctuation of the calculated results is small (it changes by only ±0.001), it is clear that there is a high variation of the error coefficient. It is possible to combine all sets (total of 5,000 years), which will reduce the error coefficient to around 8% (i.e. 27 faults in 5,000 years, corresponding to a mean fault rate of 0.0054). This again confirms that longer simulation times are required to achieve the required (or desired) error coefficient in this simple case of a single component.

The MSC approach with 1,000 years of simulation has a higher error coefficient, but requires much shorter simulation time than the 10,000 years of simulation (at least ten times shorter). In practice, there is a trade-off between the error coefficient and required computational time, and in this thesis all MCS simulations are performed with the total simulation period of 10,000 years. As a general guidance for achieving a reasonably low coefficient of error, it is envisaged for input parameters with two decimal points to apply MCS with 1,000 years of simulations, while for input parameters with three decimal points, 10,000 years simulations should be applied. For input parameters with more than four decimal points, no clear recommendation for increasing the period of simulation can be given, as much longer simulation times might be required in that case, even prohibiting the completion of the simulations, unless high (parallel) computational resources are available.

Another important factor in the MCS approaches is based on the inclusion and control of the precision estimation. This is illustrated by comparing the results of the two different MCS options. The first option allows MCS simulation to be performed fully stochastically, with no evaluation of coefficient of error, resulting in a higher coefficient of error. The second option is with precision estimation (by implementing coefficient of error in MCS procedure), which effectively controls and provides a lower error coefficient of the TTR and TTF parameters and, therefore, results in a more accurate estimation of reliability indices. Although the former option reflects and mimics the stochastic/random nature of the considered phenomena (based on the assumed probability distributions), it does not precisely follow the statically defined input mean values (e.g. fault rates and MTTR). The following assessment shows the difference between the two options for the same example of a 0.4 kV busbar with 0.005 faults/year. Table 3.5 shows the comparison output parameters for fault rates by two different options of precision.

Table 3.5: Comparison of output parameters for fault rates by two different options of precision estimation

10,000 Years of Simulation	Stochastic MCS procedure (Option 1)		MCS procedure with precision estimation (Option 2)	
	Output fault rates (fault/year)	Error coefficient (%)	Output fault rates (fault/year)	Error coefficient (%)
Set 1	0.0038	24	0.0049	2
Set 2	0.0069	38	0.0051	2
Set 3	0.0057	14	0.0052	4
Set 4	0.0045	10	0.0051	2
Set 5	0.0064	28	0.0050	0

Based on the results in Table 3.5, there are noticeable differences in the results of the two options. All results in all simulation runs are generally different, due to the use of a random number generator in the MCS procedure, but the option with precision estimation is more consistent. In Option 1, the error coefficient is greater than 10%, i.e. it does not reflect the input (and output) mean value of 0.005 faults per year; for Option 2, the error is much smaller, around 2%. Similar differences will be present in the output PDFs for the two options. The ultimate decision for the precision control will depend on the (pre-simulation) assessed ranges of variations of input parameters.

The MCS approach creates "fluctuating" outputs and although there is no clear guidance, by increasing the number of samples, the error bound will decrease (or the confidence range will increase), allowing to use the coefficient of variance as a measure for the achieved accuracy level and as the "stopping criteria" of the MCS process. Again, various definitions can be used, but the coefficient of variance should be formulated as an estimator/measure of the dispersion of the output results corresponding to the ratio between the standard deviation and mean output value.

Generally, the coefficient of variance depends on the output results. As long as the mean value of the output deviates from the statically expressed input mean data, the MCS calculations must continue until the output mean value is close to the input mean value, or until the coefficient of variance becomes lower than the (prespecified) acceptable tolerance limit. For example, a typical tolerance limit/level in [23, 51] for frequency of short and long interruption (e.g. SAIFI or MAIFI) is specified as 7%, while limits for the durations of interruption (e.g. SAIDI, CAIDI and ENS) is 12%. On the other hand, another stopping criterion for the MCS process is error coefficient. The difference between the error coefficient and variance coefficient is in the selection of the input or output data. The error coefficient uses input parameter (e.g. input mean fault rates or input MTTR values), while variance coefficient uses output parameter (e.g. calculated/output mean fault rates or MTTR values) as the benchmark target.

3.5 Comparison of Analytical and Probabilistic Reliability Assessment Methodologies for Offshore Renewable Generation System

This section illustrates previously discussed aspects of the reliability assessment procedures and presents the results of the reliability analysis during the planning stage of offshore renewable (i.e. wind) generating plants and interconnecting MV networks. Both analytical and probabilistic reliability calculation methods are implemented and compared during the assessment, in order to obtain a more confident estimation of the operational reliability performance. Furthermore, standard reliability performance indices (related to frequency and duration of faults and related interruptions), as well as other energy-related reliability indicators are presented and compared, in order to identify the best combination of network configurations, network interconnections and generation technologies. The benefits of each case, expressed in terms of e.g. reduction of interrupted or curtailed energy outputs, are assessed against the actual cost. This is a suitable example for the previously considered general analysis, as improving reliability and availability of the offshore generating plants and networks, i.e. reducing revenue losses due to reliability-related events (for instance, faults of the components), requires correct assessment of the reliability of both individual plant components and complete offshore generating plant, including interconnecting network. This example differs from all other network examples in the further chapters of the thesis for the reason of illustrating versatility of the presented approaches.

3.5.1 Input Reliability Data

The reliability of an offshore renewable generating system (ORGS) can be assessed with confidence only if the relevant input data for the analysis are represented as the statistically significant datasets, which are typically available after many years of operation. Although it can be generally concluded that the current available reliability data and information do not allow performing an in-depth analysis of the ORGS, an extensive review of the available reports and other published literature was performed in this thesis, in order to estimate the main input parameters required for the reliability analysis of the ORGS. For example, the results of several field studies from the Reliawind project, representing a total of 35,000 downtime events involving 350 wind turbines, are compiled and processed in [52], indicating that power module (converter and associated switchgear and transformer) and wind turbines' pitch control system are the most frequent causes of faults and downtimes. Power cables (inter-array and export cabling installations) were responsible for around 1%-5% of faults/downtimes. Reliability statistics is typically collected from 10-min average turbine and substation SCADA databases, fault logs per turbine and substation, as well as monthly operational reports compiled by the wind farm operators and/or manufacturers. Tables 3.6 and 3.7 overleaf show the reported values of the main reliability analysis parameters, giving the minimum, maximum and average values of the fault rates and mean repair times, which are used specifically for the analysis of the reliability performance of a typical medium-sized wind-based ORGS in this thesis.

3.5.2 Analysed Medium Size ORGS

Among the different possible ORGS configurations, Figure 3.7 shows the selected configuration for further analysis, while the corresponding network and component parameters are listed in Table 3.8. This assessment is aimed at comparing the reliability performance with and without normally open switches at the ends of the wind turbine radial strings (inter-array cables), in order to assess the feasibility of installing these switches in the final design of the ORGS configuration.

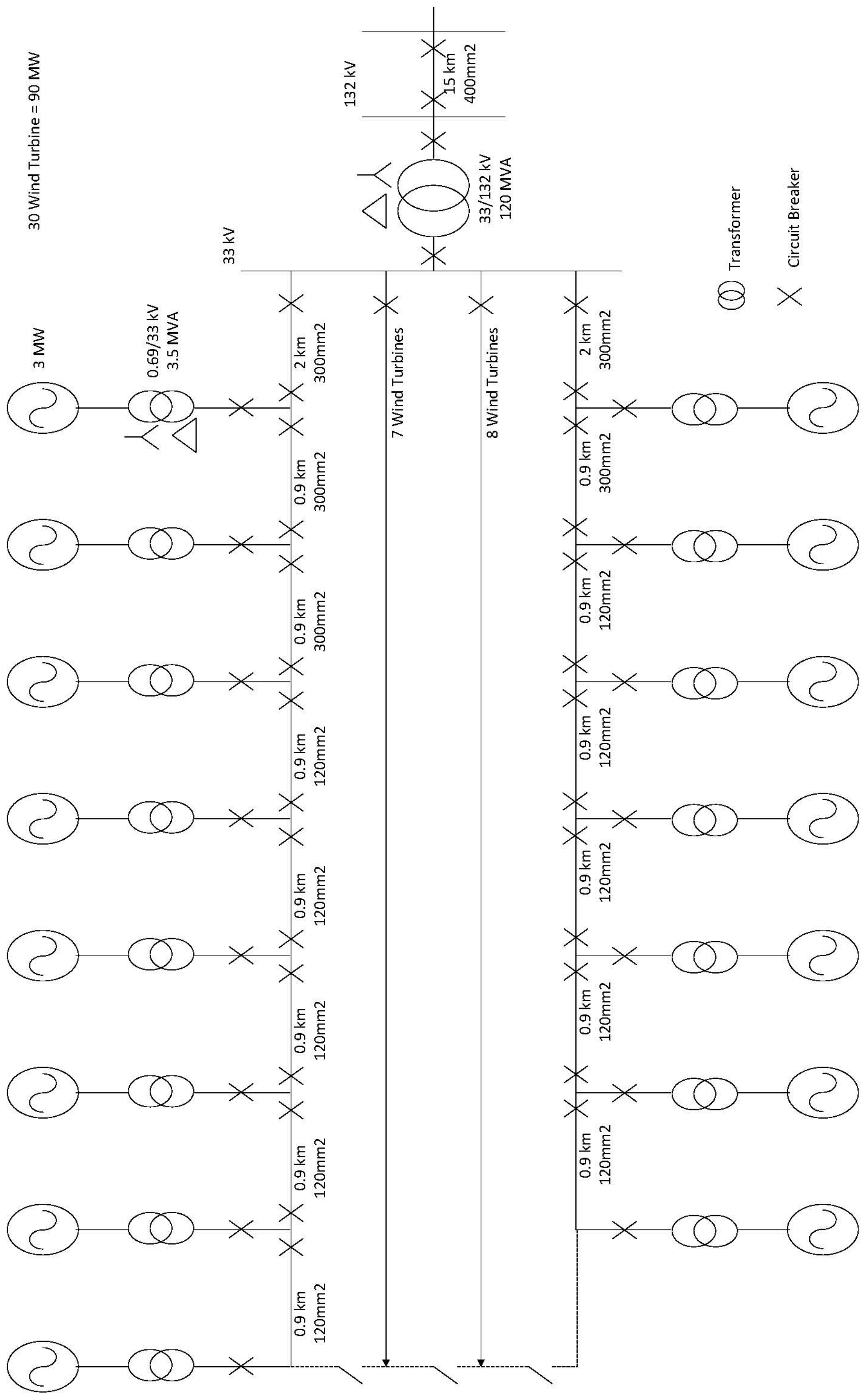


Figure 3.7: Typical medium size ORGS configuration selected for the analysis [53, 54, 55, 56, 57, 58, 59].

Table 3.6: Statistics on fault rates (with indicated minimum, maximum and average values)

ORGS Part	Component	Repair Time (hours/year)													
	References	[67]	[54]	[66]	[65]	[56]	[57]	[64]	[63]	[62]	[61]	[60]	Min	Avg	Max
Offshore (Internal)	Wind Turbine Generators		0.012	1	2		1.5	0.1					0.012	0.9224	2
	Nacelle Transformer (0.69/34kV)	0.013	3.00E-05		0.00771	0.013	0.013	0.013		3.00E-06			3E-06	0.00859	0.0131
	Tower Cable	0.015				0.015	0.015			2.00E-02			0.015	0.01625	0.02
	MV Breaker	0.025					0.025	0.025			0.00306		0.00306	0.01952	0.025
	MV Switch/Disconnector	0.025			0.00052	0.025	0.025				0.00012		0.00012	0.01513	0.025
Offshore (External)	MV Breaker 34kV				0.00082	0.025		0.025					0.00082	0.01694	0.025
	MV Breaker 70kV								0.03				0.032	0.032	0.032
	HV Breaker								0.03	1.25	0.00002		0.032	0.641	1.25
	HV Disconnector										0.00011		0.00002	0.00002	2E-05
	MV Busbar 34kV		5.00E-04			0.015					0.00018		0.00011	0.0052	0.015
	HV Busbar		1.25					0.005					0.00018	0.41839	1.25
	MV Cable 34kV		8.00E-03		0.00127		0.015	0.015	0.01	7.43E-03	8.80E-04	8.00E-02	0.00127	0.00912	0.015
	HV Cable		0.95	0.0002		0.015			0.01	9.45E-03	1.24E-02	3.00E-02	0.00021	0.15193	0.95
	Transformer (34/132kV)		0.035		0.006	0.013		0.02		3.44E-02			0.006	0.02155	0.035
Onshore	HV Cable			0.0002									0.00021	0.00021	0.0002
	HV Breaker								0.05				0.05	0.05	0.05

Table 3.7: Statistics on mean repair times (with indicated minimum, maximum and average values)

ORGS Part	Component	Repair Time (hours/year)													
	References	[67]	[54]	[66]	[65]	[56]	[57]	[64]	[63]	[62]	[61]	[60]	Min	Avg	Max
Offshore (Internal)	Wind Turbine Generators		720	144	144		490	240					144	347.6	720
	Nacelle Transformer (0.69/34kV)	240	240		144	240	240	240		60			60	200.571	240
	Tower Cable	240				240	240			48			48	192	240
	MV Breaker	240					72	240			240		72	198	240
	MV Switch/Disconnector	240			144	240	240				240		144	220.8	240
Offshore (External)	MV Breaker 34kV				144	240		144					144	176	240
	MV Breaker 70kV								720				720	720	720
	HV Breaker								720	20			20	370	720
	HV Disconnector										240		240	240	240
	MV Busbar 34kV		96			1440					240		96	592	1440
	HV Busbar		72					144			240		72	152	240
	MV Cable 34kV		288		144		1440	288	2160	192			144	752	2160
	HV Cable		720	144		1440			720	504	2160	1440	144	1018.29	2160
	Transformer (34/132kV)		702		144	240		400		504	1980	4320	144	1186.86	4320
Onshore	HV Cable			120									120	120	120
	HV Breaker								50				50	50	50

Table 3.8: Parameters of the typical medium size ORGS components selected for the analysis [68, 69, 70, 71].

Component	R	X
	(p.u. on 100 MVA)	
33kV Submarine Cable (300 mm^2)	0.0073 per km	0.0104 per km
33kV Submarine Cable (120 mm^2)	0.0184 per km	0.0118 per km
132kV Submarine Cable (400 mm^2)	0.0004 per km	0.008 per km
Nacelle Transformer (0.69/33kV)	-	1.2
Transformer (33/132 kV)	0.007	0.244

3.5.3 Results for Analytical and Probabilistic Assessment of the ORGS Reliability Performance

The concepts of reliability and availability of network components and the whole offshore renewable generating system (ORGS) are analysed in this section. The ORGS reliability performance is quantified and compared for all considered cases using the "Estimated Energy Not Supplied" (EENS) index. This approach allows a straightforward assessment of the impact of different reliability (and power quality) events and disturbances, as it translates frequency and duration of downtimes of the ORGS components and plant as a whole into the electrical energy (MWh), which is either not produced, or can be produced, but it cannot be exported to the onshore grid. The equation used for the calculation of the EENS index is:

$$EENS = \sum_{i=1}^{N}(\lambda_i P_i r_i) \tag{3.7}$$

where: N is the total number of power components, λ_i is the mean fault rate of the i-th component, P_i is the unavailable or installed power of the i-th component when component is faulty, and r_i is the mean time to repair the faulted i-th component.

As mentioned previously, the output of the analytical reliability performance assessment methods is one set of calculated indices and parameters, which are in the presented analysis extended to three sets of output results, corresponding to the minimum, maximum and average values of the mean fault rates and mean repair times from Tables 3.6 and 3.7. These three sets of results are selected for calculation due to uncertainties in the actual values for wind-based ORGS shown in Figure 3.7.

Furthermore, the analysis of the ENS index required estimation of the generating capacity not available for exporting, and for that purpose an average capacity factor during downtime of 40% is assumed. This means that 40% of the rated power of all wind turbines not able to operate, or to export produced energy due to a fault or failure within the ORGS, was assumed to be lost for the whole duration of the downtime event.

The results from Table 3.9 show that better reliability performance is obtained if the ORGS is designed with normally open switches at the ends of the radial strings of wind turbines, which will close after a fault in any of the strings is cleared by the protection system and, in that way, provide connection for the remaining wind turbines in the faulted string (downstream the fault location) to export the generated electricity.

In order to assess the range of possible losses in profit and income due to the downtimes of wind turbines for any related fault within the ORGS, an average cost of £140/MWh is assumed in the next analysis, based on [72]. If the average values of fault rates and mean repair times are used, the estimated lost profit is about 10.5% of the total generated power outputs (£44,150,400) if there are no switches that allow connection at the end of the radial strings. However, if the switches are installed, the estimated lost profit is reduced to about 9.9%, representing reduction of 0.6%.

Table 3.9: Analytical assessment of EENS index.

ORGS Design	Failure Rates and Repair Times	Exp. Energy Not Supplied (EENS) (MWh/year)	Estimated Profit Losses (£/year)	Estimated Profit Losses (%)
Without switches at the ends of radial strings	Minimum	308.824	43,235.36	0.1
	Average	33,176.501	4,644,710.14	10.5
	Maximum	136,605.506	19,124,770.84	43.3
With switches at the ends of radial strings	Minimum	244.408	34,217.12	0.1
	Average	31,167.430	4,363,440.20	9.9
	Maximum	129,414.100	18,117,974.00	41

The results for the probabilistic reliability performance assessment (Monte Carlo approach, with 1,000 years of simulation) provide not only mean/average values of the calculated indices and parameters, but also provide information on their distributions. Both analytical results (Table 3.9) and probabilistic results (Table 3.10) are closely matched, thus providing more confident estimation of reliability performance. This is illustrated in Table 3.10 (mean values of EENS index for both analysed cases) and in Figures 3.6-3.9 (distribution of EENS index values for both analysed cases), with again assumed average capacity factor during the downtime of wind turbines of 40%.

Table 3.10: Probabilistic assessment of EENS index.

ORGS Design	Failure Rates and Repair Times	Exp. Energy Not Supplied (EENS) (MWh/year)	Estimated Profit Losses (£/year)	Estimated Profit Losses (%)
Without switches at the ends of radial strings	Minimum	292.80	40,992.00	0.1
	Average	31,237.06	4,373,188.40	9.9
	Maximum	111,491.34	15,608,787.60	35.4
With switches at the ends of radial strings	Minimum	217.736	30,483.04	0.1
	Average	29,457.7	4,124,078.00	9.3
	Maximum	106,945.01	14,972,301.40	33.9

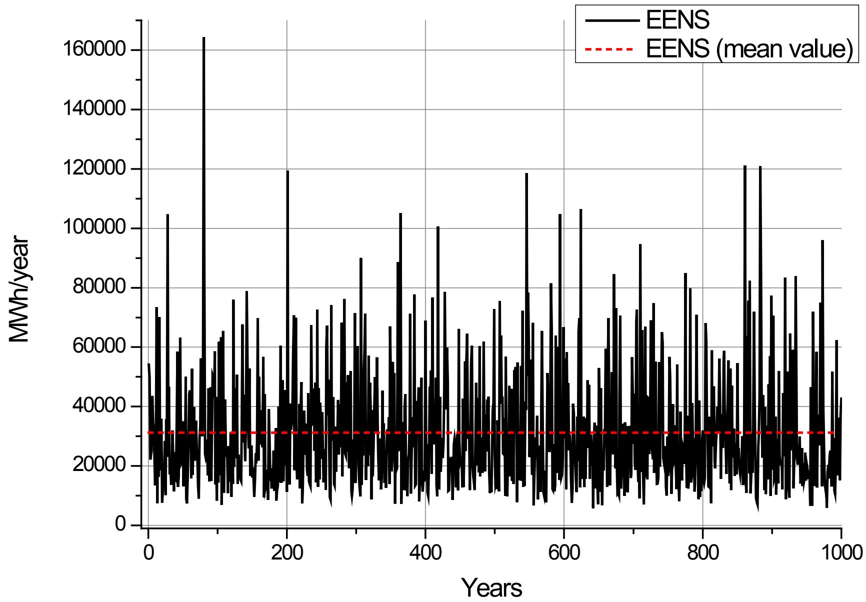


Figure 3.8: Calculated EENS values throughout 1,000 years of simulation for ORGS design without switches at the end of radial strings (average input parameters)

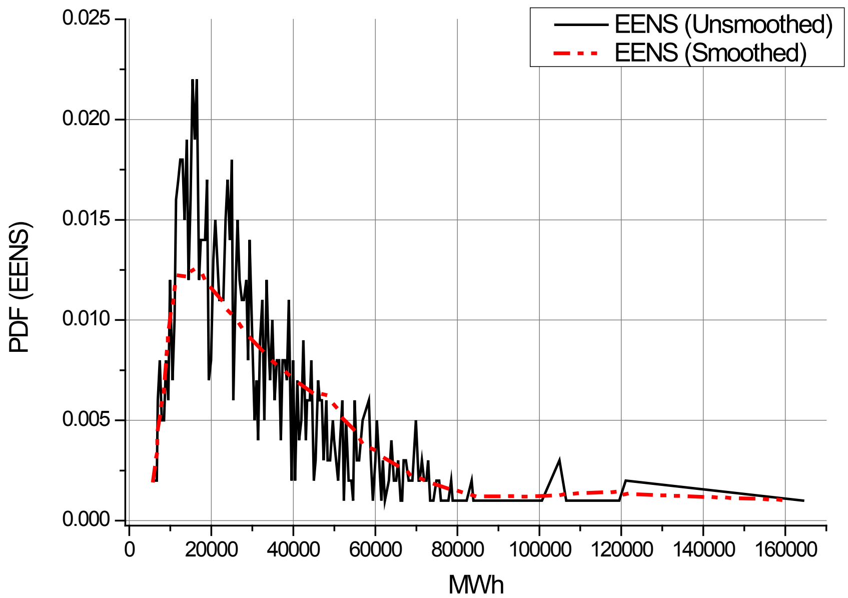


Figure 3.9: PDF of EENS values for ORGS design without switches at the end of radial strings (average input parameters)

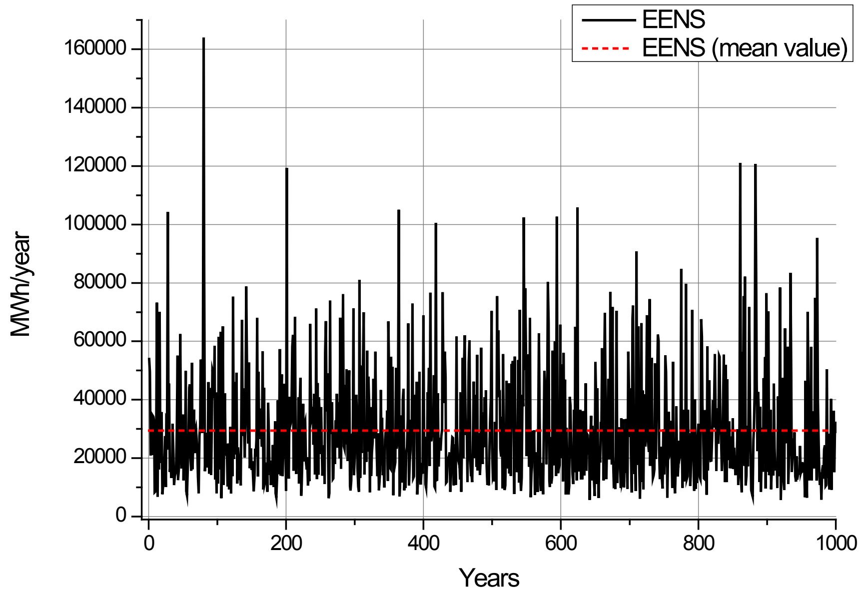


Figure 3.10: EENS values throughout 1,000 years of simulation for ORGS design with switches at the end of radial strings (average input parameters)

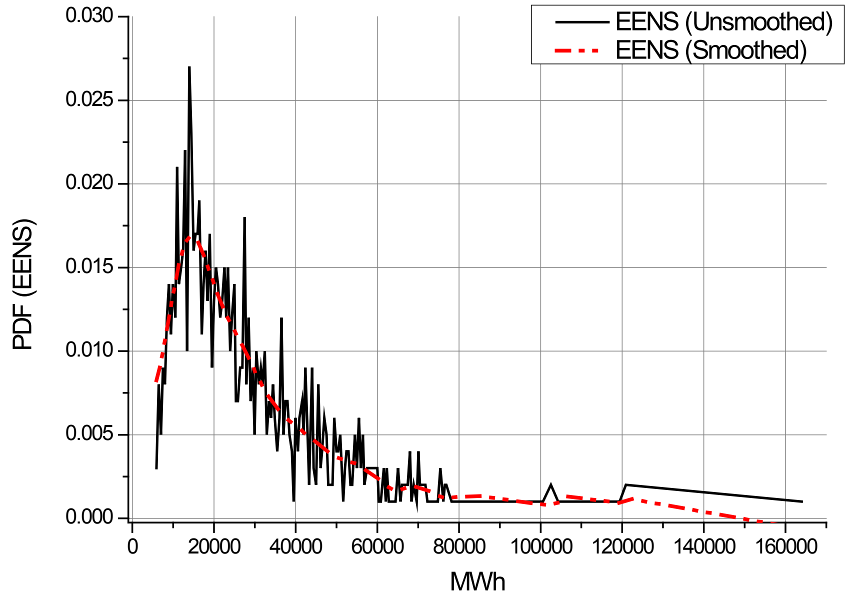


Figure 3.11: PDF of EENS values for ORGS design with switches at the end of radial strings (average input parameters)

It is interesting to note that if the selected medium-sized ORGS is designed with switches at the ends of radial strings of wind turbines, the improvement in the reliability performance is relatively small (~0.6%), as MV cables are reliable components, and also allow for a simple replacement, instead of a repair. The cables are modelled with average values of 0.009116 faults/year (i.e. once in a hundred years) and 752 hours of mean repair time (i.e. around 30 days), in accordance to data in Tables 3.6 and 3.7. In other words, investing in these switches may not repay the investment, but the presented analysis is essentially an indication and ultimate decision should be based on a more detailed evaluation of the actual costs of switches and cables, the size of the ORGS, location and weather-specific repair/replacement times and costs of these repairs/replacements, etc. For the purposes of this thesis, this example was used to illustrate the main aspects of the discussed analytical and probabilistic reliability assessment approaches, as well as their implementation in conditions significantly different from the standard analysis of the LV and MV (onshore) distribution networks.

3.6 Chapter Summary

This chapter discussed and presented background analysis of a number of the relevant aspects of two main reliability assessment techniques, commonly denoted as analytical and probabilistic approaches. The step-by-step algorithms for the implementation of both approaches are given and their general advantages and disadvantages are discussed.

Analytical approaches provide only mean values of output reliability indicators, but require shorter computational times, while probabilistic approaches present more comprehensive results, but require longer computational times, depending on the size of the network, total simulation period and steps of the simulation.

The results of the MCS process produce fluctuating outputs due to the stochastic effects, therefore requiring specification of a stopping criteria and analysis of the convergence of output results in terms of acceptable errors and limits/boundaries. In order to analyse these conditions and requirements, two types of precision indicators are simulated and discussed in this chapter (variance coefficient and error coefficient). Generally, these two coefficients are different, as variance coefficient uses mean output values for benchmark, while error coefficient uses mean input values. Another factor affecting the accuracy of MCS approaches is related to the total period of simulation. These factors need to be correlated with each other before starting the process of simulations. Lastly, the MCS outputs can be defined in various probability distributions during the integration of random number generator with input parameters. To illustrate the main aspects of discussed analytical and probabilistic reliability assessment approaches, an example of the offshore wind plant is used.

Chapter 4 Modelling of LV and MV Distribution Networks: Generic Network Models

Identifying network configurations, sizes and types of network components and other relevant network characteristics and parameters (e.g. the lengths of the lines, the numbers of the connected customers, etc.) is not only important from the point of view of providing required input data for the reliability assessment. The detailed data and information on modelled networks are crucial for obtaining accurate results of the analysis. Accordingly, this chapter focuses on the typical LV and MV distribution networks in the UK and Scotland, for which all required data and information on network configurations, components, parameters and characteristics were obtained after an extensive review of available statistics, reports and other literature, mostly from the UK/Scottish distribution networks operators (DNOs).

In the UK, distribution networks are normally operated in radial configurations, starting from the step-down transformers (e.g. 132/11 kV, or 132/33 kV), representing bulk grid-supply points (GSPs), which from the primary distribution substations supply a number of underground cable or overhead line feeders, which vary in lengths and sizes. Finally, in order to deliver power to customer loads at suitable voltage levels (e.g. three-phase 400 V or single-phase 230 V), secondary substation transformers are connected along the MV feeders, which themselves supply LV networks up to the service connections of the individual customers.

4.1 LV/MV Network Design Criteria

In order to identify the models of the typical UK/Scottish LV/MV networks, the design criteria and characteristics of these network should be analysed first. For instance, the size of the feeder at different locations is determined by both maximum supplied demand and short circuit levels, which vary for different fault types. Protection devices detect the faulty condition/location/level, in order to properly and selectively clear the faults (using e.g. circuit breakers or fuses) and isolate the faulted sections and limit impact of service supply interruptions on connected customers. The typical design fault levels for the UK distribution networks are shown in Table

4.1, which gives indicative values of maximum fault currents for different voltage levels.

Table 4.1: Typical UK symmetrical fault currents and fault levels [73, 74]

Voltage (kV)	Fault current (kA)	Fault level (MVA)
132	21.9	5000
33	17.5	1000
11	13.1	250
0.4 (LV)	34.8	25

The next important step during network modelling is to identify the type of the protection system installed within the network, as well as the corresponding settings. Most faults on the underground cables are permanent faults, e.g. from excavation, soil movement and equipment failures. This differs from the overhead lines, which are exposed to external and weather-related factors, such as winds and storm, snow and ice loading, lightning, animal and tree contacts. Faults due to some of these external factors are considered as momentary/temporary faults, and overhead line networks are usually equipped with automatic recloser circuit breakers (ARCBs). The guidelines of installing ARCBs in the UK are given in [75]:

i. More than 1 km of overhead lines (including spur/lateral lines) shall be equipped with AR at sources (substations), or at another CB.
ii. Not more than 500 customer between AR
iii. Not more than 2000 customer per circuit
iv. A maximum of three AR devices at 11 kV.

However, some considerations must be given to disabling the ARCBs in the substation and for installations of ARCBs at the first main sections of overhead lines, where the first section from the primary substation consists entirely of underground cables that supply more than 50 customers [76]. In addition, the type of the applied protection devices for lateral/spur feeders depends on the length of the feeders:

i. Long spurs (lines longer than 5 km) shall be protected by AR.
ii. Medium spurs (lines between 0.5 km and 5 km) shall be protected by a sectionaliser.
iii. Short spurs (lines less than 0.5 km) shall be protected by a fuse.

As for the LV network, most feeders and LV sides of secondary distribution transformers are typically protected by fuses with different ratings and clearing times. However, it is more suitable to install circuit breakers for the protection of the first feeder section and also in the middle of a long LV main feeder (typically with multiple radial spurs/laterals), when there is usually a large secondary distribution transformer, which is then also protected by circuit breaker at LV side, in order to reduce the impact of interrupting large number of customers due to non-permanent faults. The MV sides of secondary distribution transformers are protected by circuit breaker for easier maintenance and replacement of transformers, LV busbar and fuses in substation, etc. Within the MV/LV secondary substation, the CB-based protection devices are designed to operate with three-pole activation, in order to avoid unbalanced supply.

Typically, due to capital cost and lower impact on customers (i.e. lower numbers of interrupted customers), the design of UK LV networks is not based on N-1 security criteria and LV networks are always operated in fixed radial configurations. Therefore, there are no redundant components in the LV secondary substation, which feature only a single transformer per LV load point. As for the MV network, it is preferred to install a matched pair of primary transformers, to provide N-1 security. Additionally, a number of parallel feeders supplied from a MV primary substation are operated in “normally open” radial configuration, i.e. with a normally open connection to another parallel feeder, which can be closed (manually or automatically) to form a meshed/ring MV network configuration, or to provide alternative supply point to another MV substation. On the other hand, for certain areas with lower demands, it is more economical to install only a single primary transformer (in rural networks), or to locate and operate normally a open device (in sub-urban networks) to split the load approximately 50/50 over two halves of the ring or, sometimes, 60/40 is applied, depending on the circumstances [77].

4.1.1 Fuse-saving scheme

The fuse-saving scheme is designed to prevent the activation of fuses during transient faults. Although in this scheme transient faults will result in SIs, this is assumed to contribute to a higher reliability performance (i.e. lower duration of supply interruptions), as the time required to change the fuses activated by transient faults will result in LIs. This scheme typically uses automatic reclosing circuit breaker (ARCB) in a low-set instantaneous overcurrent protection, which will the trip feeder CB before any fuse on the lateral branches operates. The CB is then automatically reclosed, which will restore the supply if the fault is transient, preventing fuse replacement. In case of permanent faults, ARCB will allow the fuse nearest to the fault to operate after a few reclosing attempts.

The main disadvantage of the fuse saving scheme is that all customers within the protection zone of the ARCB will experience short supply interruption(s) for temporary faults on branch fuses, which are essentially unnecessary in case of permanent faults. At MV level, fuse-saving schemes are applied in sub-urban and rural MV networks by utilising ARCBs, but not in highly-urban and urban MV networks, since all protection devices there are CBs, which might also feature automatic reclosing functionalities. Since the fuse-saving scheme requires additional equipment (instantaneous overcurrent relays with automatic reclosing functionalities), it is not applied in LV networks.

4.1.2 Fuse-blowing scheme

This scheme is allowing the fuse to trip first during both permanent and temporary faults, and is also called trip-saving or breaker-saving scheme. With this scheme, all customers connected to the faulted feeder will experience long supply interruptions due to the operation of the dedicated fuse, except in case of (very) short duration transient faults. For such transient faults, the fuse will not operate and customers will experience either a short interruption, or a voltage dip.

4.2 Single-Phase and Three-Phase Network Operation: Importance of Full LV Network Models

Most of the existing studies prefer modelling of distribution networks as symmetrical three-phase networks, using the corresponding single-line network representations, as that substantially simplifies the analysis. Generally, this assumes that the protection components (e.g. circuit breakers or fuses for "feeder cut-off", i.e. disconnection of faulted feeders) operate in a three-pole mode of operation. This means that for asymmetrical single-phase and double-phase faults, which are typically 5-6 times more frequent than the three-phase faults, the protection component will disconnect all three phases, not just the faulted one(s). Generally, this reflects the correct application and setting of the three-pole protection systems in MV networks, but it is not likely for the UK LV networks, where most of the customers are connected to a single-phase 230 V supply and where fuses, as the most common protection components, are operated in a single-pole mode. Conversely, using a single-line representation of LV networks means that there will be no distinction between the different fault types and that the assessed number of interrupted customers will be significantly overestimated. Accordingly, if this aspect of the LV network design is not accurately modelled, the assessment of reliability performance of LV networks will not be correct.

4.2.1 Importance of Considering Different Types of Faults

The design of the networks takes into account the statistics of different fault types. The faults can be classified into single-phase, two-phase (with and without earth) and three-phase faults. In available literature, the statistics on the different types of faults is given for both HV and MV networks, while statistics on the types of faults in LV networks is scarce. Again, this shows that more emphasis in the past analyses was given to HV and MV networks, with much lower attention to LV networks, most likely due to a much lower impact in terms of the number of interrupted customers (compared to MV and HV networks). In order to help the analysis of MV and, particularly, LV networks, Table 4.2 shows the percentage contributions of different fault types identified in existing literature. The calculation of average values is based on a simple arithmetic mean formula (for example, the value for single-phase faults for MV level mixed overhead, O/H, and underground, U/G, network is obtained as the average of two reported values of 50% and 70%, i.e. as 60%).

Table 4.2: Percentages of different fault types in LV and MV networks

kV	**Phase fault**	**References**							**Average**		
		Mix [78]	O/H [79]	Mix [80]	O/H [81]	O/H [82]	U/G [83]	O/H [84]	O/H	U/G	Mix
LV	S	-	-	-	-	-	-	78	50	50	50
	D	-	-	-	-	-	-		10	10	10
	DG	-	-	-	-	-	-		18	18	18
	T	-	-	-	-	-	-	22	22	22	22
MV	S	50	70	70	80	65	76	-	71.6	76	60
	D	9	15	15	2	9	0	-	8.7	0	12
	DG	24	10	10	17	20	24	-	15.7	10	17
	T	17	5	5	1	6		-	4	14	11

4.3 Modelling of MV/LV Distribution Networks

In this thesis, residential customers are classified in four general, i.e. "generic" subsectors, based on their location (e.g. urban or rural), size (small, medium or large), the geographical dispersion (concentrated or distributed load points), and the type of residential dwelling (flat or house) [85]. This classification into four different subsectors allows to specify the typical configurations and components (types and sizes) of the LV and MV networks supplying residential customers at different locations, ranging from highly-urban, through urban and sub-urban, to rural areas.

In each subsector, depending on the location, there will be different configurations, arrangements of network components and protection systems, as well as differences in network operating conditions. In urban and large city areas, where the load density is high and customers are evenly distributed, the feeders are shorter and underground cables are used due to limited space for overhead lines and substations, increased reliability and aesthetic reasons. On the other hand, in sub-urban and rural areas, the customers are non-evenly distributed, as the dwellings are typically in proximity of the roads, resulting in longer overhead feeders and lower demand densities.

This section presents further updates and additional details on the four generic LV and MV networks, which are initially considered in [5].This was stipulated as one of the tasks of this PhD research, as, for example, previously modelled MV networks did not include “direct transformation” by 132/11 kV transformers in highly urban areas, or detailed consideration of single-pole fuses in overhead rural networks.

4.3.1 Four Generic Residential Load Subsectors

In this thesis, “load sector” is defined as the aggregation of loads, i.e. electrical devices and equipment, which are used for certain purpose and in specific applications by the end-users performing similar activities and tasks. The alternative term to load sector is “customer class” and some of the commonly used load sectors are, e.g., residential, commercial, industrial, agricultural, etc. The load structure and load composition in one load sector usually exhibit similar characteristics, as well as patterns of active and reactive power demands, allowing to use similar (load) models for the representation of the aggregate demands of all users in that load sector. The simplest approach, which typically does not introduce large errors, is to use the same general load profile for the representation of the aggregate demand in one load sector. This approach is used for the representation of aggregate demands in the four different generic residential load subsectors in this thesis, based on the location, size, and type of residential dwellings, [85].

Based on the differences in general characteristics and parameters of supplying LV and MV distribution networks, the residential load sectors can be further divided into the four following generic sub-sectors: highly-urban, urban, sub-urban, and rural. Similar approach is previously used to make distinction between residential load sub-sectors based on “building area efficiency” and “load density”, reflecting land use control and construction conditions in the built environments. The building area efficiency is expressed as a density measure, which is defined as the ratio of floor area of the built environment and the total geographical area. This is illustrated in Table 4.8, which is adopted from [86]. An additional difference between the different subsectors is the level of public and street lighting.

Table 4.3: Area efficiency and MV load density (MWh/km^2) for various load sectors [86].

Area efficiency	HU	U	SU	R
Low	0.8	0.3	0.13	0.05
Medium	1.9	0.74	0.26	0.11
High	3.3	2.1	0.52	0.18
MV load density	HU	U	SU	R
Low	13	3.2	1.4	1.3
Medium	41	10.9	3.6	3.1
High	137	24.9	6.9	6.5

4.3.2 Highly-urban (HU) residential load sub-sector

This residential sub-sector is usually found in large cities ("metropolitan" areas), where residential dwellings are multi-storey and high-rise buildings, representing highly concentrated grid supply points. In large cities, the building area efficiency exceeds unity, which means the multi-storey buildings are built densely, often side-by-side. High building area efficiency also indicates restriction of land-use, as, for instance, limited or no space is available for air-insulated equipment and switchgear (e.g. lines, or outdoor transformer substations). Furthermore, the presence of the dedicated public and street lighting is greater than in other sub-sectors, due to the presence of parking spaces and higher required levels of lighting of streets and public spaces in metropolitan areas.

4.3.3 Urban (U) residential load sub-sector

This residential sub-sector consists of house-type dwelling, ranging from one to few-storey buildings, located in city urban areas and characterised by medium to high concentration of power demand. The building area efficiency also exceeds unity, but is somewhat reduced than highly-urban building area efficiency. It has the same restrictions for space availability, which again limits the network components and network construction in outdoor applications. The load demand from public/street lighting in this sector is also high, but reduced with respect to highly-urban area.

4.3.4 Sub-urban (SU) residential load sub-sector

This residential load sub-sector represents individual house dwellings located in city sub-urban areas and towns, which are in close proximity to big cities and characterised by medium to low power densities. The building area efficiency for this sector is below unity, which indicates less buildings and higher space area availability. The mixture of load structure is almost similar with that of urban sector, but the contribution of public and street lighting is reduced.

4.3.5 Rural (R) residential load sub-sector

This residential sub-sector represents house-type dwellings, ranging from one to few-storey buildings located in more remote areas. The houses/buildings are located far from each other, resulting in low power density and dispersed demand. Since the available space is vast, it normally has much lower building area efficiency than that in sub-urban sector and the network components installation are typically aerial feeder type and outdoor type switchgear. Another noticeable difference from the other sectors is minimum, or almost no presence of public/street lighting.

4.3.6 Two General Types of Networks and Network Components

The selection of network components mainly depends on the load density and distribution of supplied customers in the served geographic/network area. An important additional factor is space availability, as “space” is one of the most-valued commodities in urban and highly-urban areas, where space restrictions and limitations have direct impact on the selection of component types (enclosed and compact components with suitable type and level of electrical insulation). Accordingly, the two following general types of network components can be distinguished:

i. Air-insulated and open-air network components (e.g. air-insulated switchgear (AIS), air-insulated lines (AIL) and pole-mounted transformers)
ii. Enclosed network components, with gas, liquid or solid insulation (e.g. SF6 circuit breakers and oil-type insulation).

As mentioned for (highly) urban areas, where available space for network component is limited, network components are enclosed and insulated with pressurized gas (SF6) or solid insulation, where enclosed/indoor installations are located within the buildings. Underground cable conductors are used to provide environmental protection and for aesthetic reasons. On the other hand, there is a much larger availability of space in sub-urban and rural areas, where components with air insulation are used, requiring larger insulation distances due to relatively low dielectric strength, as in the case of bare overhead conductors.

4.4 LV Residential Networks

LV networks in the UK are typically configured as radial networks, operating at 415 V three-phase, or 230 V single-phase voltages. A LV network starts after stepping down a primary voltage of 33 kV or 11 kV by either 33/0.4 kV or 11/0.4 kV secondary distribution transformers. The characteristics (size, location, protection, etc.) of secondary transformers will differ in different LV networks. In urban and highly-urban areas, where the load density is high, the secondary transformer is located within a multi-storey (residential or commercial) buildings, or in a stand-alone enclosed secondary substation. In sub-urban and rural areas, often only a pad-mounted or pole-mounted transformer is used, due to more dispersed customers and lower demands. The selection of LV distribution feeder, which can be in the form of underground cable, aerial cable or overhead line, also depend on the availability of space and load density, i.e. "cost per served customer". Accordingly, Table 4.3 provides some general information (types and cross-sections of LV distribution feeders and spurs) typically used in the UK. Additionally, Table 4.4 provides a more detailed information for direct use in the four generic network models: highly-urban (HU), urban (U), sub-urban (SU) and rural (R), allocating identification letters for each line in the generic network models in Figs. 4.1-4.8.

Table 4.4: Typical characteristics of LV feeders in the UK [39, 87, 88, 89, 90]

Highly-Urban/Urban Underground Network	
Interconnector	Cross-Sections (mm^2 Al)
Main trunk feeder	4x300; 4x185; 4x120
Lateral spurs	4x185; 4x120; 4x95
Service connection	4x120; 4x95; 4x70; 4x35 2x35(Cu)
Sub-Urban/Rural Aerial Network	
Interconnector	Cross-Sections (mm^2 Al)
Main trunk feeder	4x120; 4x95; 4x70
Lateral spurs	4x95; 4x70; 4x50
Service connection	4x70; 4x50; 4x35 2x35(Cu); 2x25(Cu)

Description of the LV distribution network is incomplete without the secondary MV/LV step-down transformers. Typically, the MV/LV substation comprises of a single transformer, with a rating from a few tens kVA up to 1.5MVA. Normally, in the UK, the primary (MV) winding of transformer is connected in delta, in order to isolate the earth faults on the secondary side and cancel the zero-sequence component. The secondary (LV) winding is connected in star and earthed (with neutral conductor), enabling supply of single-phase loads, i.e. typical residential customer loads, connected between the phase and neutral conductors, with an operating voltage of 230 V. Table 4.5 provides detailed information on typical 11/0.4kV transformers in the UK, again directly correlated with the four generic network models in Figs. 4.1-4.8.

Table 4.5: Typical characteristics of LV feeders in the UK, as used in the presented generic network models in Figs. 4.1-4.8 [14, 15, 17, 18, 19, 20, 21, 22, 23, 24, 25]

Subsector	LV Line type: Id.	LV Line type: Configuration	Cross Sectional Area (CSA) (mm^2)	Positive sequence (Z) R_{ph} (Ω/km)	Positive sequence (Z) X_{ph} (Ω/km)	Zero sequence (Z) R_0 (Ω/km)	Zero sequence (Z) X_0 (Ω/km)	Maximum sustained current Iz_{ph} (Amps)
HU	A	Underground Line (Cable) EPR or XLPE 0.6/1 kV 4x(CSA) Al / Cu (earth) CNE	300	0.1	0.073	0.593	0.042	465
HU/ U	B		185	0.164	0.074	0.656	0.05	355
	C		120	0.253	0.071	1.012	0.046	280
	D		95	0.320	0.075	1.280	0.051	245
U	E		70	0.443	0.076	1.772	0.052	205
	F		35	0.87	0.085	3.481	0.058	156
SU	G	Overhead Line Aerial Bundled Conductor (ABC) XLPE 4x(CSA) Al	120	0.284	0.083	1.136	0.417	261
	H		95	0.32	0.085	1.355	0.406	228
SU/ R	I		70	0.497	0.086	2.387	0.447	195
R	J		50	0.397	0.279	2.570	0.396	168
	K		35	0.574	0.294	3.372	0.345	148
HU/ U/S U	L	Service Connection PVC or XLPE 0.6/1 kV 1x(CSA) Al / Cu (neutral / earth) CNE	35	0.851	0.041	3.404	0.03	120
SU/ R	M		25	1.191	0.043	4.766	0.03	100

where: EPR - Ethylene propylene rubber, XLPE - Cross-linked polyethylene, PVC - Polyvinyl chloride, CNE – Combined Neutral Earth, Al – Aluminium, Cu - Copper

Additionally, the secondary distribution systems are also designed based on the requirements for dielectric and mechanical strength, thermal capacity limits and voltage regulation. The maximum thermal capacity of a network component is determined by the maximum allowed temperature for the conductor insulation (underground cables), or the maximum elongation (sagging of overhead lines). The thermal capacity limit is related to the current capacity limit, but actual operating conditions (ambient temperature, wind speed, etc.) might have additional impact.

Finally, the total voltage drop between the LV side of the secondary substation and the last served customer (the farthest load point on the feeder for the maximum demand conditions) should be within the maximum permitted voltage variation limit in a LV network, which is between +10% and -6% of the nominal voltage in the UK.

Table 4.6: Typical characteristics of the UK 11/0.4kV secondary distribution transformers [91, 94, 101]

Subsector	Operating Voltage (kV)	Transformer Rating (kVA)	Connection	Tapping Range	Load Losses at 75°C (W)	No-Load Losses (W)	Impedance (%)	Model Parameters (p.u. on 100 MVA)	
								R_{LV}	X_{LV}
HU	11/0.4	1500	Dyn11	± 5% in 2.5% taps	15810	1400	5	0.70267	3.2584
		1000			11000	1350	4.75	1.1	4.62
HU/U		800			7410	1000	4.75	1.1575	5.8225
U		500			5100	680	4.75	2.04	9.28
U/SU		315			3420	580	4.75	3.4444	14.6794
SU		200			2900	540	4.75	7.5	22.5
SU/R		100			1750	320	4.5	17.5	41.45
R		50			1100	190	4.5	43.72	78.6
	11/0.23	25	-		400	110	4.5	64.0076	146.6424.

For each residential load sub-sector, the network diagram provides information on MV/LV transformer size (Table 4.5), the length of LV feeder with cross-section (Table 4.4), and the number of LV customers at each load point with total demand.

4.4.1 Highly-Urban Generic LV Network Model

Highly-urban (HU) LV distribution network model is defined for large cities and metropolitan areas with concentrated demands and heavy loading conditions. The networks are designed with indoor type of substations/switchgear and underground cable lines in radial configuration. The typical HU LV network in the UK is assumed to have four main three-phase feeders, supplied from LV busbars of the infeeding 1.5 MVA 11/0.4 kV substation, as shown in Figs. 4.1 and 4.2. The four main feeders are protected by circuit breakers, supplying several lateral branches (spurs) with a maximum number of 380 single-phase connected customers, represented by 19 load points, LP1 to LP19. The protection devices are either circuit breaker or fuse, depending on the number of supplied customers. Since the main feeder supports a large number of customers, it is likely that a circuit breaker is used as protection device. Due to high load density and voltage regulation limit, the length of the feeders is short (with lines identified in Table 4.4).

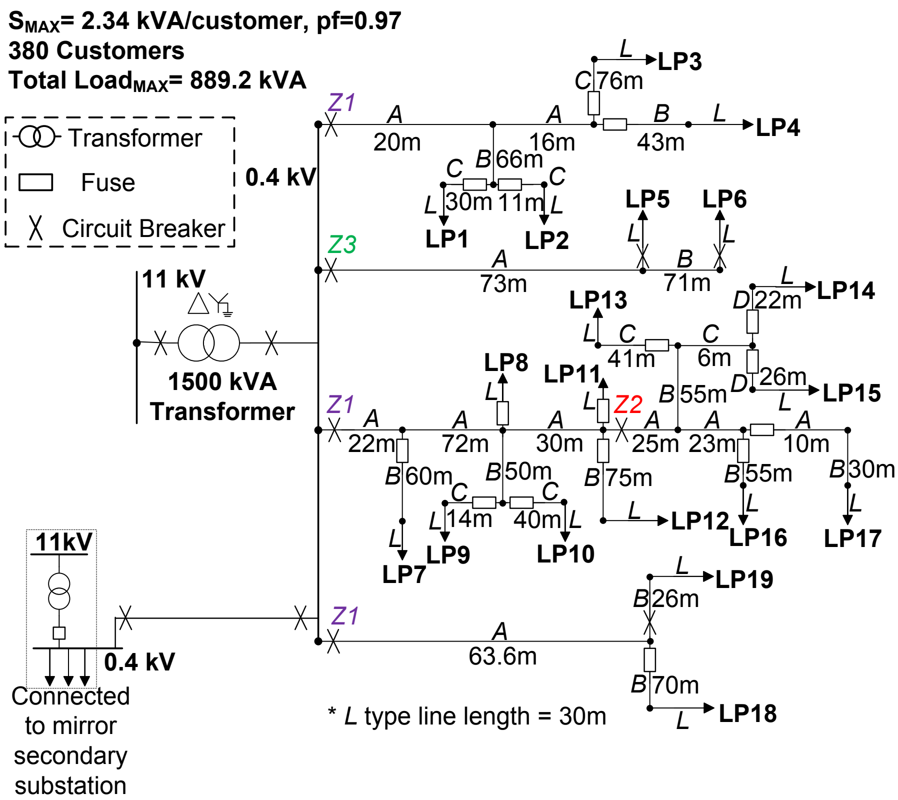


Figure 4.1: Single-line model of generic LV highly-urban network [77, 102, 103, 104, 105].

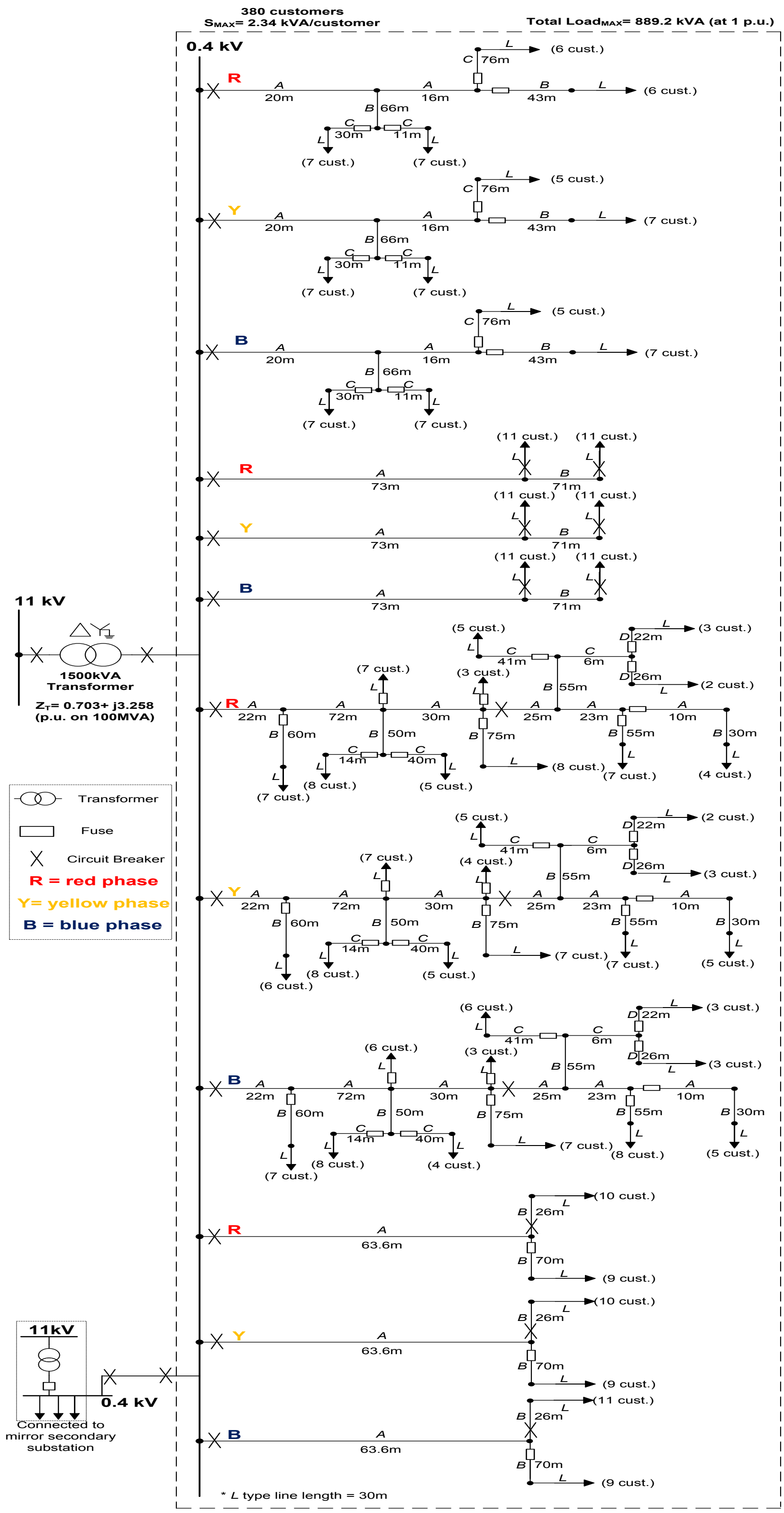


Figure 4.2: Full three-phase model of generic LV highly-urban network [77, 102, 103, 104, 105].

Furthermore, according to [71, 73], Scottish Power (DNO in Scotland) provides designs of highly-urban LV networks with normally-closed alternative supply from the similar adjacent ("mirror") highly-urban LV distribution network (type 'X' LV network). The provision of the alternative supply maintains continuous supply to the customers for faults originating from the LV substation (i.e. MV/LV transformer and circuit breakers), or from the upstream 11 kV feeder (Figure 4.9). In order to further improve continuity of supply, each lateral feeder is connected to a LV pillar, which contain either fuse or circuit breaker (based on the connected customers) to isolate the faulty downstream section from the rest of the network.

The maximum/peak load is 862.6kW, the minimum load is 142.5kW [39], both for assumed power factor pf=0.97. The selection of transformer with the rating of 1.5 MVA, which is almost twice the maximum load, is to accommodate 1-2% annual increase of load [71, 73], as well as to provide continuous supply to adjacent LV highly-urban customers. Excluding the 30 m long service cable connection (marked as 'L' type of lines in Table 4.4), the highly-urban network has the total length of underground cables of 1,222 m: 300 mm^2 (355 m), 185 mm^2 (601 m), 120 mm^2 (218 m), and 95 mm^2 (48 m).

4.4.2 Urban Generic LV Network Model

The generic urban (U) LV distribution network model is similar to the generic HU LV network model, but has lower number of connected customers and, therefore, operates at lower loading conditions (around 50% lower). The typical 11/04 kV transformer is with a power rating of 800 kVA and, as the available space inside the city urban areas is rather limited, all MV/LV substations and switchgears are of indoor type. Again, underground cable lines are used for distributing power in radial configuration, as shown in Figs. 4.3 and 4.4. Main feeders are protected by circuit breakers, while lateral feeders are protected by fuses. The network is able to supply a total of 190 single-phase customers, connected to 19 load points (LP1 to LP19).

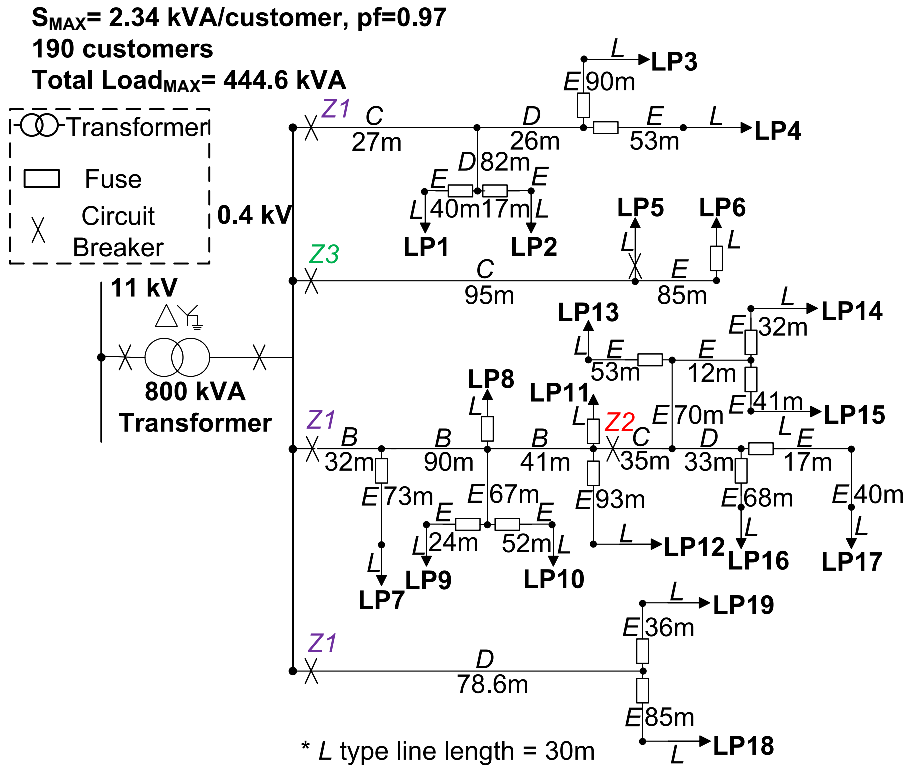


Figure 4.3: Single-line model of generic LV Urban network [39, 77, 102, 103, 104].

The configuration of the generic urban network lacks N-1 security for secondary distribution transformer and substation main circuit breaker, as there is no provision of alternative supply point via an additional cable from adjacent "mirror" MV/LV substation. The maximum demand is 431 kW, while minimum demand is 71.25 kW [39]. Again, the size of the transformer is almost twice the maximum loading condition, in order to accommodate an increase of 1-2% each year and possible expansion of the LV network. The total length of underground cable network is 1,587.6 m (feeders are longer than in HU LV network model): 300 mm^2 (122 m), 185 mm^2 (41 m), 120 mm^2 (157 m), 95mm^2 (219.6 m), and 70 mm^2 (1,048 m).

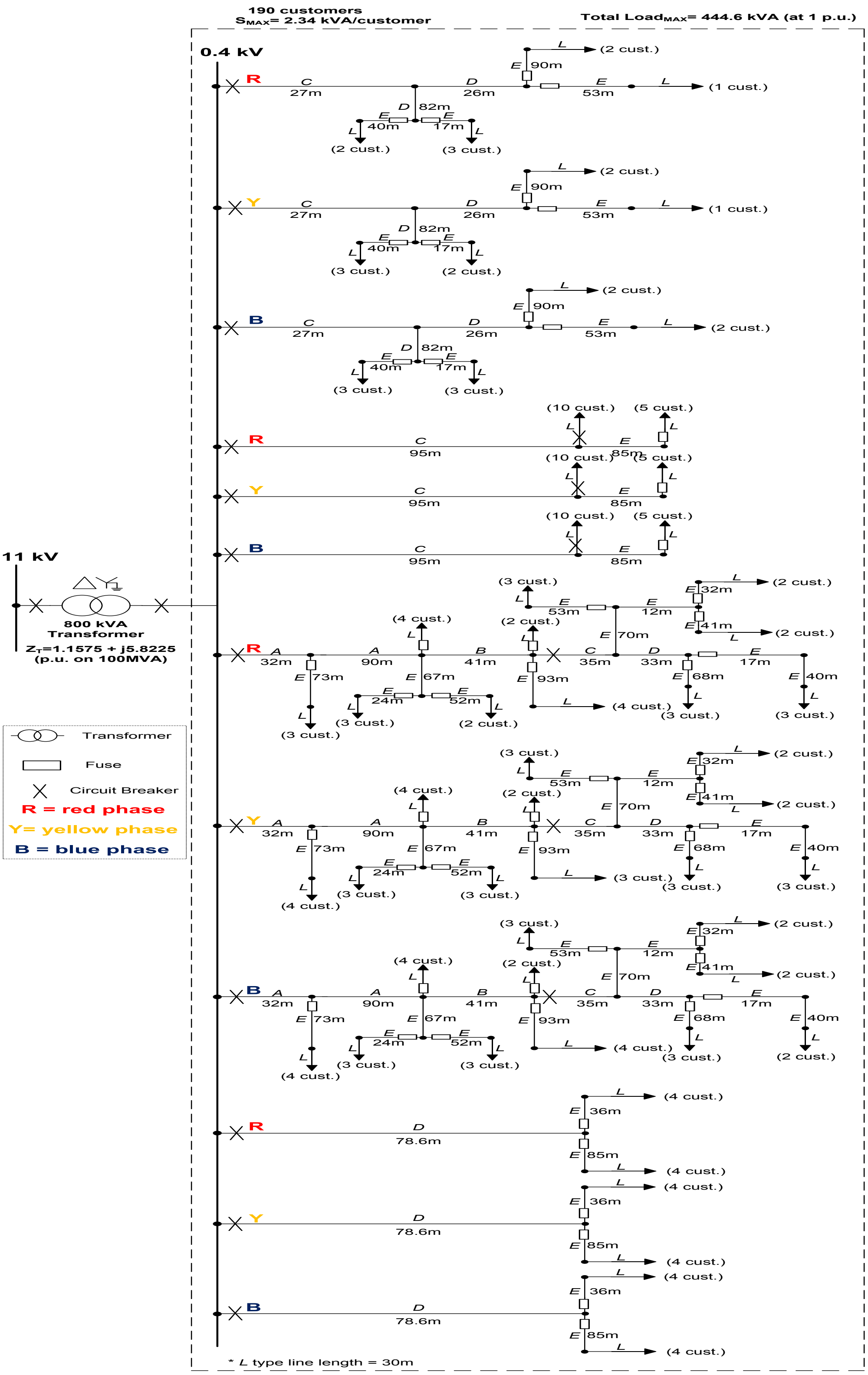


Figure 4.4: Full three-phase model of generic LV urban network [39, 77, 102, 103, 104].

4.4.3 Sub-Urban Generic LV Network Model

The generic sub-urban (SU) LV network model is defined for smaller towns and sub-urban areas around the big cities, with medium to low load demands. From MV/LV substation, the powers are transferred to customers via overhead lines, and although it is common to use bare conductors due to lower capital cost, some sub-urban areas are using aerial cables for better reliability, as bare conductors are considered vulnerable to environmental and external impact, such as lightning, snow, animal, trees and wind. The typical arrangement consists of several overhead main feeders, with about 30 m of pole-to-pole distance, in radial configuration. Supplied load points in this network are with lower demands, and typically only the feeder head is protected by a CB, while branch/lateral feeders are protected by fuses, as shown in Figs. 4.5 and 4.6.

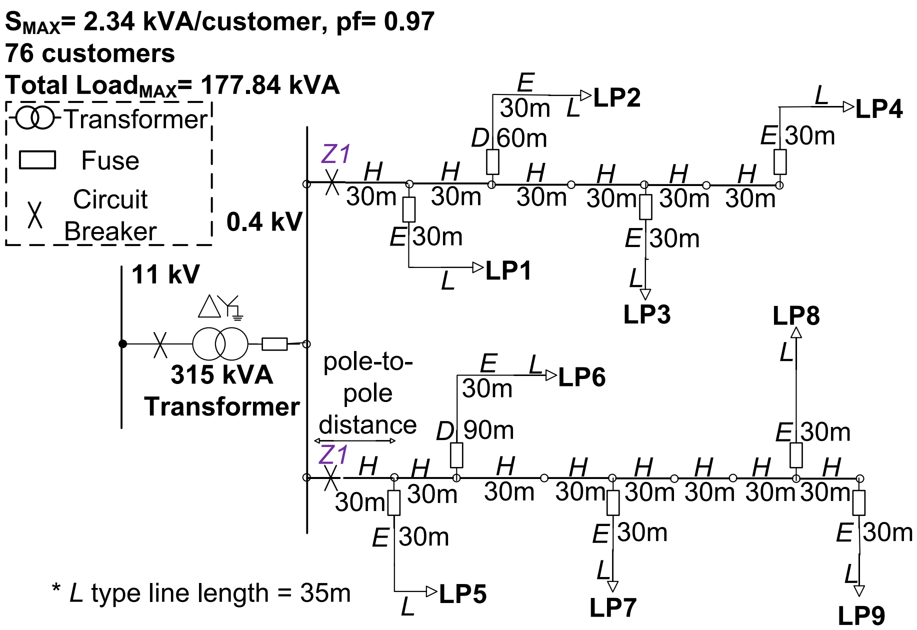


Figure 4.5: Single-line model of generic LV sub-urban network [77, 97, 101, 103, 104, 106].

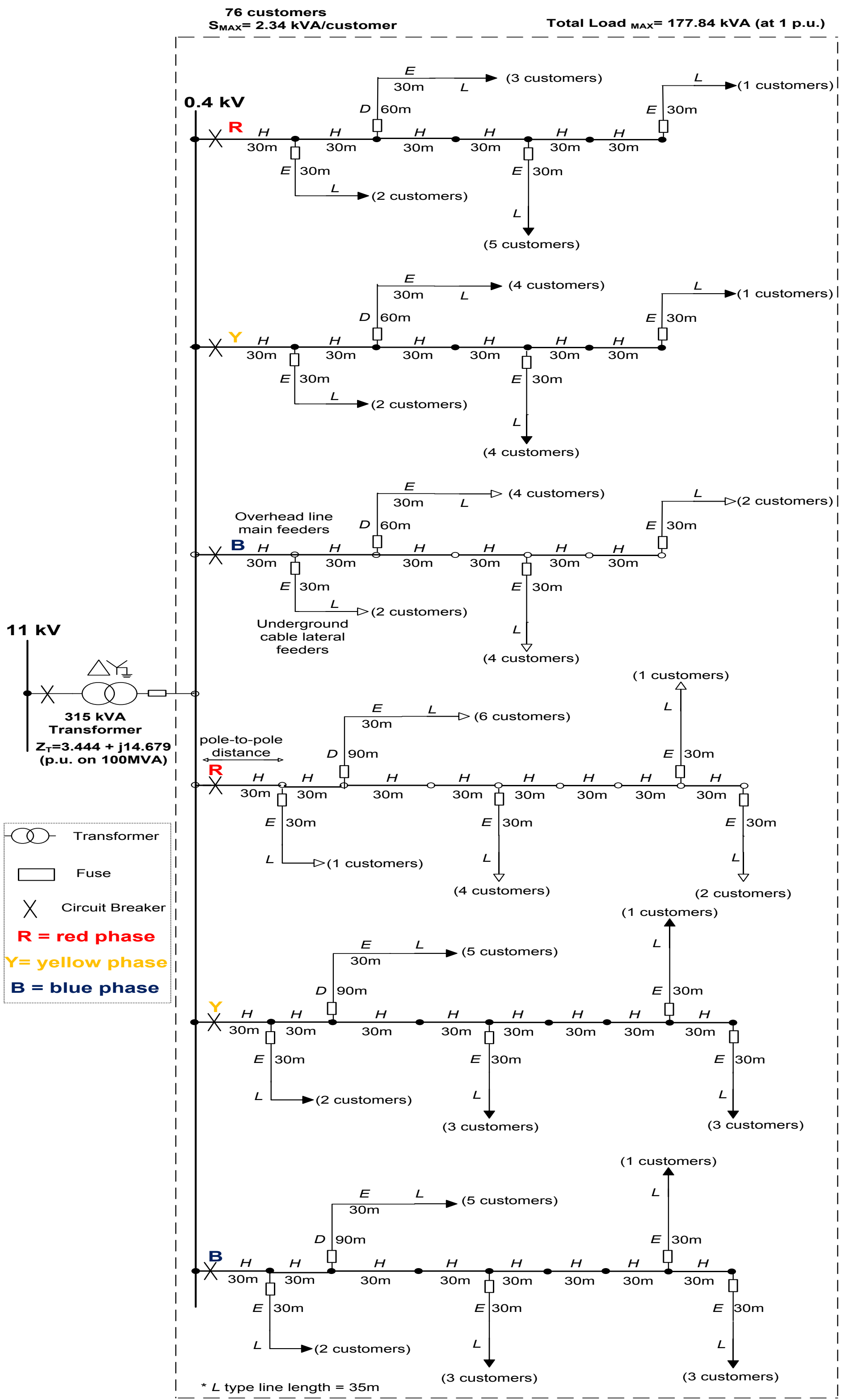


Figure 4.6: Full three-phase model of generic LV sub-urban network [77, 97, 101, 103, 104, 106]

The generic SU network has no redundancy (N-1 security for distribution transformer and substation main fuse) and no alternative supply point. The substation and switchgear for this network are of the outdoor type and the maximum rating of transformer is 315 kVA, supplying a total of 76 customers connected to nine load point (LP1 to LP9), with maximum demand of 172.5 kW and minimum demand of 28.5 kW [39]. Excluding the service cable ('L' type) lengths, this network has the total length of 840 m, with mixture of overhead lines (OHL main feeders) and underground cables (lateral feeders): OHL 95 mm^2 (420 m), cable 95 mm^2 (150 m), and cable 70 mm^2 (270 m).

4.4.4 Rural Generic LV Network Model

The generic rural (R) LV network model is defined for supplying remote customers, located far from the city and urban areas, where load demand is low and customer load points are highly dispersed. The network is radial and made from overhead conductor lines, with typically two main three-phase overhead feeders supplying 19 individual single-phase customers (each presenting a separate load point). The customers are normally located along the roads, with pole-to-pole distance of around 35 m, where each service connection supplying a single customer is protected by a pole-mounted fuse, as shown in Figs. 4.7 and 4.8.

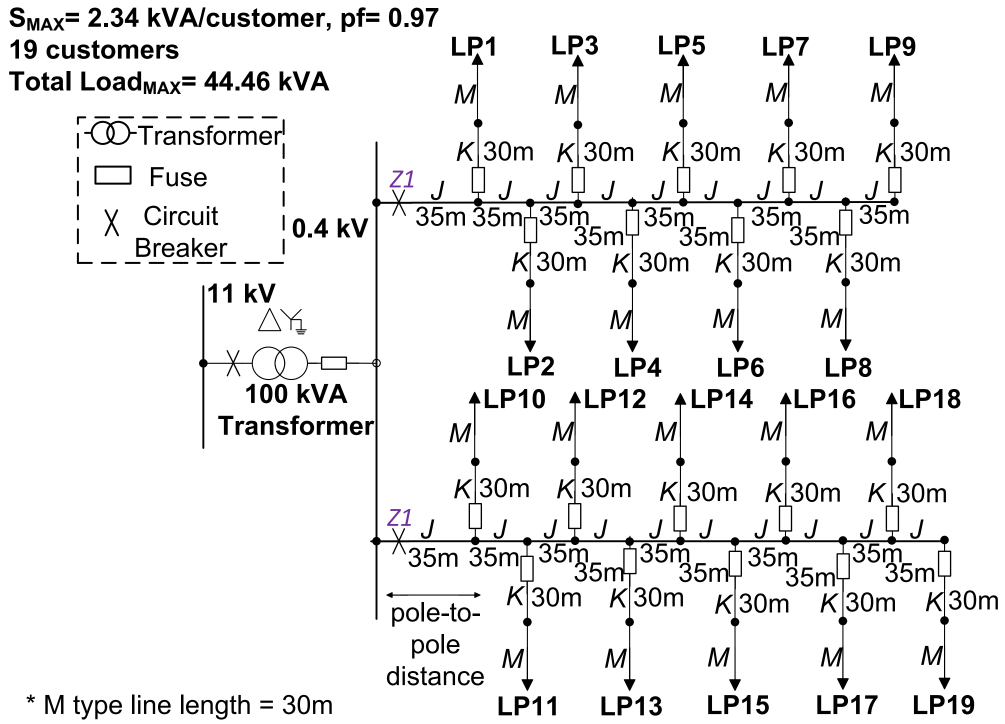


Figure 4.7: Single-line model of generic LV rural network [77, 103, 104, 106].

Although a vast amount of space is available in rural areas, most of the secondary transformers and dedicated switchgear are pole-mounted, due to its low power rating. In the generic network model, the 11/0.4 kV transformer with a power rating of 100 kVA is selected, although in certain rural areas demand could be around 50 kVA, or even lower, when it is preferable to use a single-phase secondary transformer, again in order to reduce costs. The maximum demand is 43.13 kW and minimum is 7.13 kW [39]. Excluding the service cable length ('M' type), the rural network has a total length of 1,235m, with the following OHLs: 50 mm^2 (665 m), and 35 mm^2 (570 m).

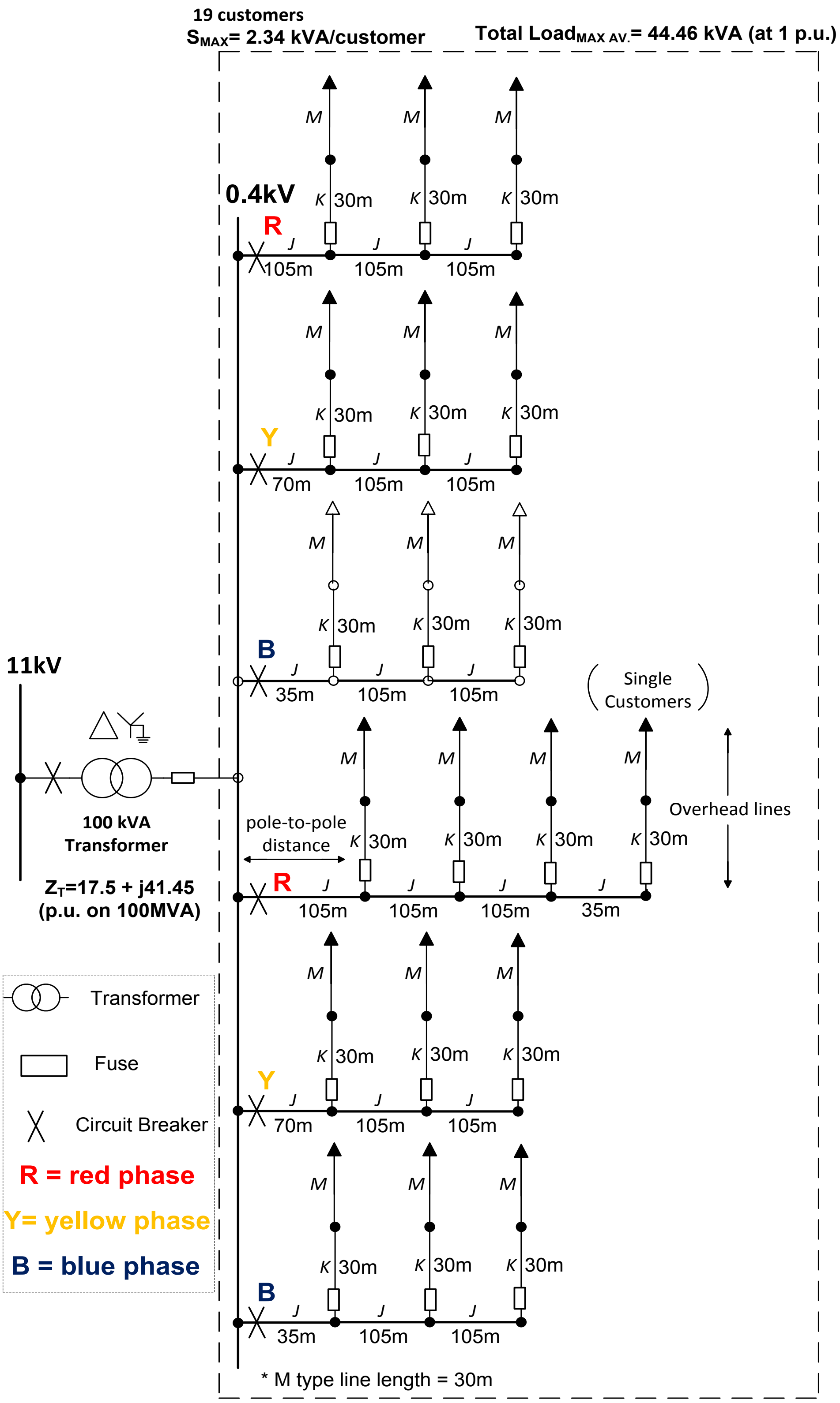


Figure 4.8: Full three-phase model of generic LV rural network [77, 103, 104, 106].

4.4 Generic MV Distribution Network Models

Following an approach similar to the formulation of the four generic LV networks, the development of the models of the corresponding four generic MV networks is presented in this section. It should be noted that the identification of MV network designs, configurations and network parameters/components requires careful consideration, as the assessed impact of supply interruptions in terms of connected customers is much higher than in the LV networks. The technical and economic factors, such as the selection of feeder type and size, switchgear and transformer rating, as well as type of protection devices, must be considered based on network area, load demand and space availability for network components. An additional aspect of analysis is related to regulatory requirements, i.e. security and quality of supply (SQSS) [107], which should be analysed together with the GSPs [108] and permissible voltage variations [19], directly affecting DNO's performance.

The modelling of MV networks considers two different voltage levels of GSPs, which are 132 kV and 33 kV in the UK. For most networks, the typical substation transformer is 33/11 kV, while (highly) urban areas, where demand is high, are supplied via direct transformation, 132 kV to 11 kV. Most of substations are equipped with two transformers operated in parallel, in order to provide better voltage control, loadability and security, whereas in rural areas with low demands a single 33/11 kV transformer is commonly used. All transformers are equipped with on-load tap changers (OLTC), in order to control the voltage of the secondary side within the prescribed range of allowed variations of ±6% of rated voltage [19].

Table 4.7: Typical characteristics of MV feeders in the UK, as used in the presented generic network models in Figs. 4.9-4.13 [73, 94, 95, 97, 109]

Subsectors			HU	HU/U	U	SU	SU/R	R
11 kV Distribution Line type	**Id**		**O**	**P**	**Q**	**R**	**S**	**T**
	Configuration		Underground Line (Cable) - (3-core PICAS cable (11kV screened, stranded Al) - (3-core XLPE stranded/ solid Al with 95 or 70mm^2 Cu wire screen)			Overhead Line - (AAAC (75°C) 150 or 100 mm2 Oak AL4) - (ACSR 54/9 mm2 11kV)		
	Cross Sectional Area (CSA)	(mm^2)	300	185	95	150	100	50
Positive sequence Z/km	R_{ph}/km	(p.u. on 100MVA)	0.09917	0.12271	0.14403	0.11259	0.14658	0.21626
	X_{ph}/km		0.06322	0.06575	0.06662	0.18363	0.26189	0.20694
Zero-phase sequence Z/km	R_0/km		0.69422	0.85896	1.00824	0.39252	0.30166	0.74174
	X_0/km		0.22128	0.23011	0.23318	0.83701	1.31330	0.99861
Susceptance	B/km		0.000269894	0.000239536	0.000178035	0.000084263	0.000012207	0.000047347
Maximum current	I_{zph}	(Amps)	525	415	355	490	395	290

The primary 132/11 kV or 33/11 kV substation typically supplies several 11 kV outgoing/main feeders, with each 11 kV feeder supplying a number of 11/0.4 kV secondary substations (as discussed in the previous sections). The selection of the type of feeder is based on the location and the space availability for network components, with Tables 4.6 and 4.7 providing the information on the type and characteristics/parameters of the four corresponding generic MV network models. Table 4.6 provides detailed information regarding the types and parameters of 11 kV feeders in the UK, together with the identification letters for modelling and classification in Figs. 4.9-4.13, while Table 4.7 provides detailed data on typical 132/11 kV and 33/11 kV transformers for each sub-sector (HU, U, SU and R).

Table 4.8: Typical characteristics of the UK 132/11 kV and 33/11 kV distribution transformers [71, 73, 92, 109, 110]

Operating Volta-ge (kV)	Subsector	Rating (MVA)	Vector group	Resistance R	Reactance X	Zero Seq. Reactance X_0	Tap Range (p.u.)		Method of Earthing
				(p.u. on 100MVA)			Min	Max	
132/11	HU	40	Yy0	0.03	0.647	0.259	0.8	1.1	Resistance
		30		0.0314	0.674	0.674			
33 / 11	HU	30	Dy11	0.035	0.78	0.5	0.8	1.04	
	HU, U	24		0.0291	0.7083	0.45	0.85	1.05	
		15		0.0833	1.088	0.54	0.9	1.05	
	U, SU	10		0.069	1	0.5	0.85	1.045	
	SU, RU	7.5		0.095	1.08	0.52			Solid / Resistance
		5		0.14	1.3	0.8			
	RU	2.5		0.3609	2.8	1.77	0.81	1.04	
where: HU - highly urban, U - urban, SU - suburban, R - rural									

4.4.1 Highly-Urban Generic MV Network Model

Highly-urban (HU) generic MV distribution network model refers to areas of big cities (metropolitan areas), where there is a large number of customers with a high concentration of demands. Accordingly, it is common to use underground cables and indoor substations/switchgears, as the space for network components is limited. The networks are strong with meshed configuration and shorter cable lengths than in other sub-sectors, in order to allow for the optimal voltage regulation.

Normally, an HU MV network has a radial configuration and it is supported by an alternative supply point, either from an MV primary substation, or from a 'reflection centre', or both. A reflection centre presents a normally open closed-loop arrangement between all ends of 11 kV main feeders that provides supply to some of the feeders in case of network faults. Reflection centre is connected to the adjacent (same) MV network, acting as alternative supply in cases when the main feeder is faulty or unable to provide supply (e.g. due to maintenance). During normal operation and without any failure, the network presents a radial configuration with normally open protection devices between the main feeders and the alternative supply/reflection centre.

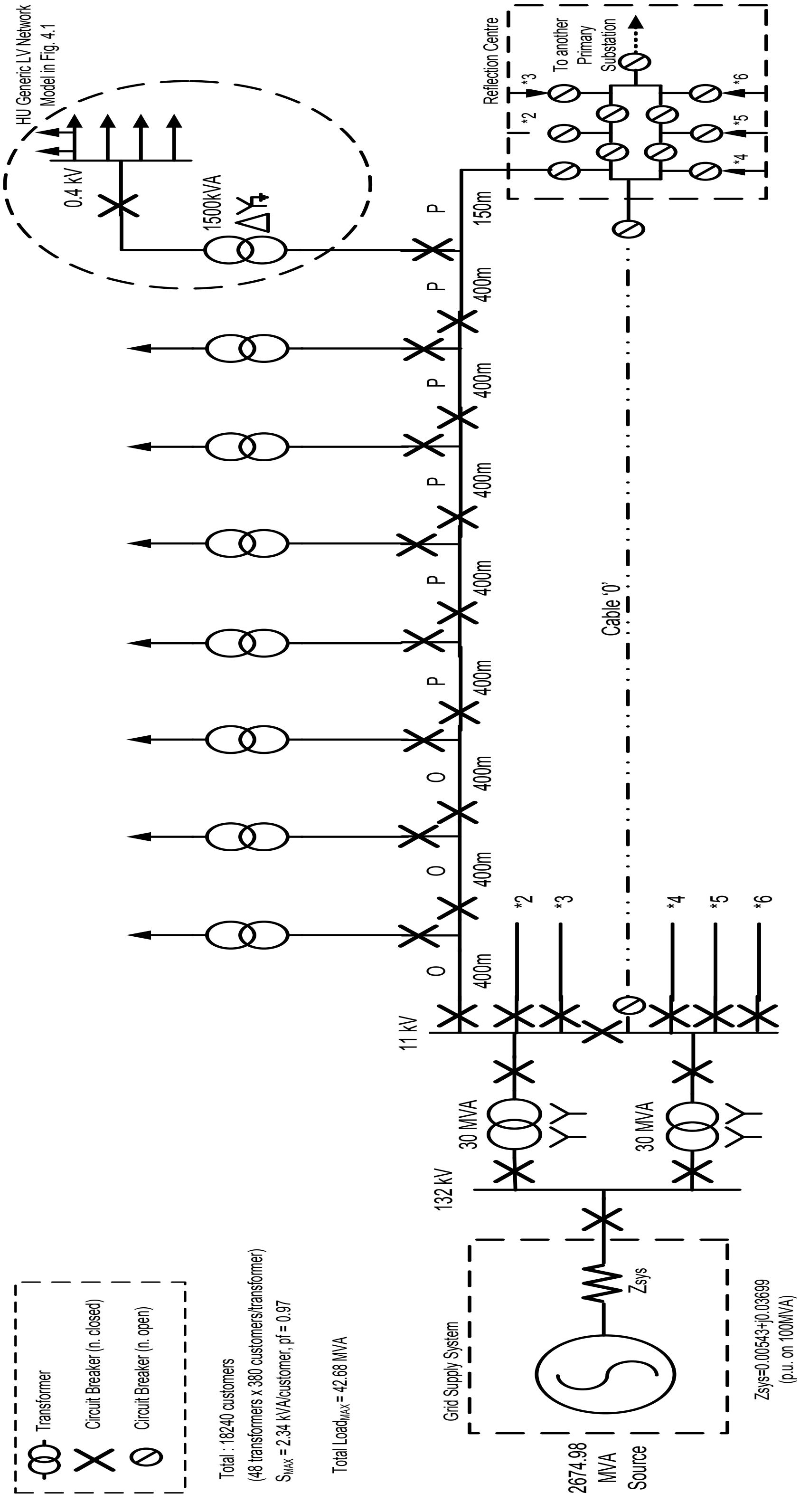


Figure 4.9: Generic MV 132/11 kV highly-urban network [75, 87, 89, 110, 111, 112]

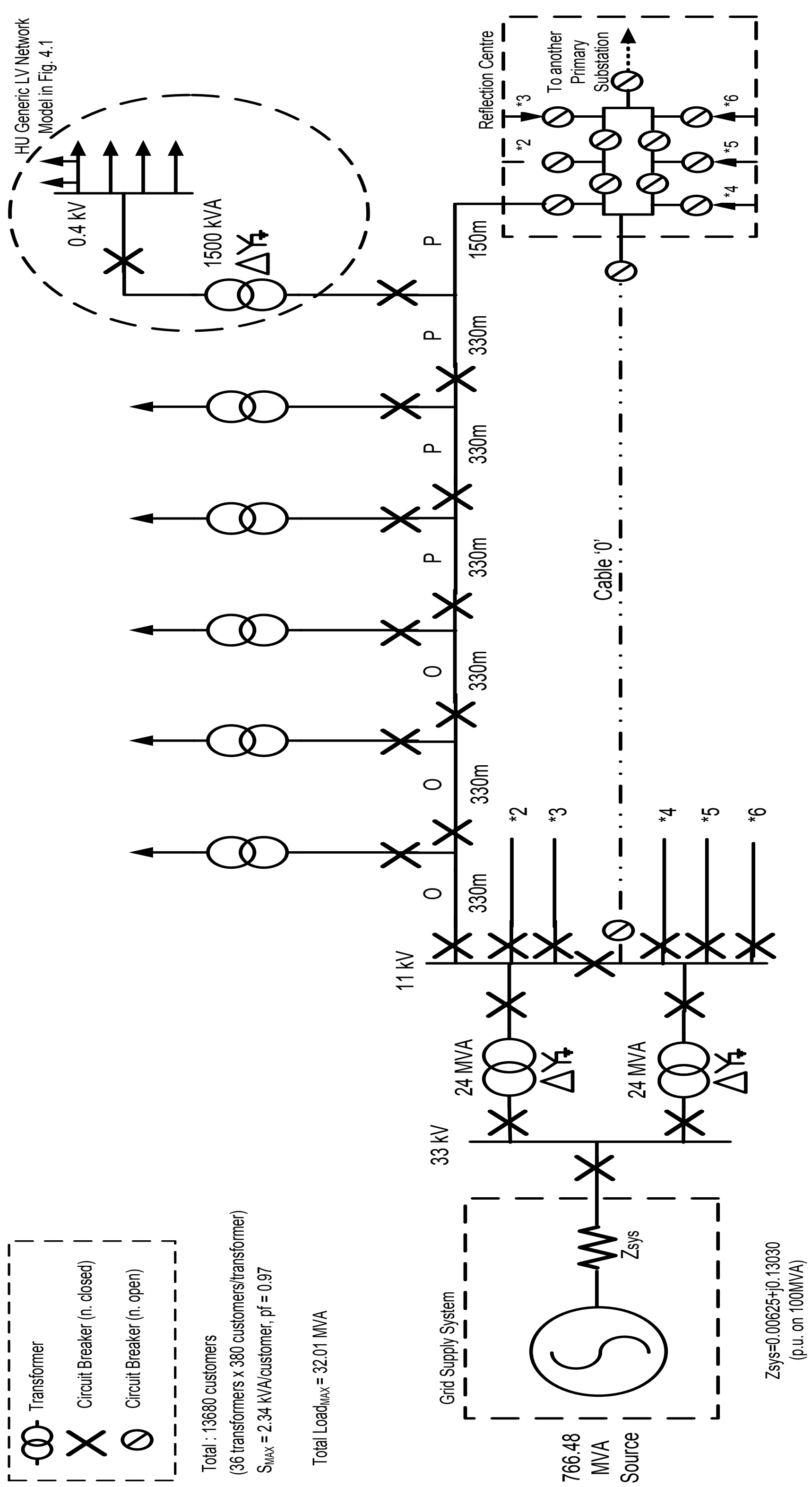


Figure 4.10: Generic MV 33/11 kV highly-urban network [75, 87, 89, [110, 111, 112]

An additional network component in HU generic network model is an 11 kV main underground cable between the 11 kV busbars in the primary substation and the reflection centre. This cable is denoted as "cable 0' and it does not carry any power during normal operation. In case of the faults on main feeders, however, the cable '0' allows for independent support of all customers (up to the rated power of two transformers) even without use of an alternative supply point from the adjacent MV primary substation. Furthermore, and as previously discussed for HU LV network, each of the MV/LV secondary substations can also support other adjacent LV networks during the faults on 11 kV main feeders, or faults of the secondary transformers. In practice, DNOs typically connect a maximum of six 11 kV main feeders to a primary HV/MV substation, with up to ten MV/LV secondary substations (generic HU LV network) on each 11 kV feeder. According to [77, 112], primary substations are operated with two parallel transformers, where each transformer should not carry more than 70% of its rated capacity during normal operation.

As illustrated in Figs. 4.9 and 4.10, there are two variants of the UK generic HU MV networks: with a standard transformation (33/11 kV) and with a direct transformation (132/11 kV). The latter is capable of supporting 18,240 customers, while the former can supply 13,680 customers, based on the previously used "after diversity maximum demand" (ADMD) level of 2.27 kW or 2.34 kVA (pf=0.97) per individual household [39]. The 33/11 kV transformation HU generic MV network has a total lengths and cross-sections of 11 kV underground cables: 300 mm^2 (5.94 km) and 185mm^2 (6.84 km) while the 132/11 kV transformation HU generic MV network consists of total length and cross-sections of 11kV underground cables: 300 mm^2 (7.2 km) and 185mm^2 (12.9 km). The first two sections of each 11 kV main feeder have larger cross-section areas due to higher loading, [77, 112]. For direct and standard transformation variants of HU generic MV networks, the total maximum demands are 41,4 MW and 31,05 MW, while minimum demands are 6,84 MW and 5,13 MW, respectively [39].

Each section of 11 kV main underground cable feeders and primary sides of 11/0.4 kV transformers are protected by a tele-controlled circuit breaker for ease of reconfiguring of network and energy transfer during certain network faults. Typically, automatic recloser circuit breakers (ARCB) are not used (e.g. [76]), as most of the faults on underground cables are permanent faults, originating from the cable itself (e.g. water ingression) and human activities (e.g. land excavation).

4.4.2 Urban Generic MV Network Model

The urban (U) generic MV network model is almost identical in configuration to the HU generic MV network, but has slightly reduced strength, transformer rating, switchgear rating and longer feeder length. The urban network also uses underground cables to transfer power to all customers and indoor type of substation/switchgear. The network is operated in radial configuration with (normally open switches providing) support from an alternative supply and reflection centre. During the faults, this network reconfigures after a faulted part is isolated, in order to provide continuous supply to all, or most of the customers (the same N-1 security and additional cable ‘0’ as in the case of HU network).

The important difference between urban and highly-urban MV networks is that there is no additional interconnection between the pairs of secondary MV/LV substations. Accordingly, although generic urban MV network is capable of reconfiguring in case of faults on 11 kV underground cable sections, or circuit breakers (cable ‘0’), the faults of MV/LV substation/switchgear result in supply interruptions, which makes urban MV network somewhat less reliable than a highly-urban MV network. The urban MV network also has a maximum of six 11 kV main feeders, with up to ten 11/0.4 kV spurs on each feeder.

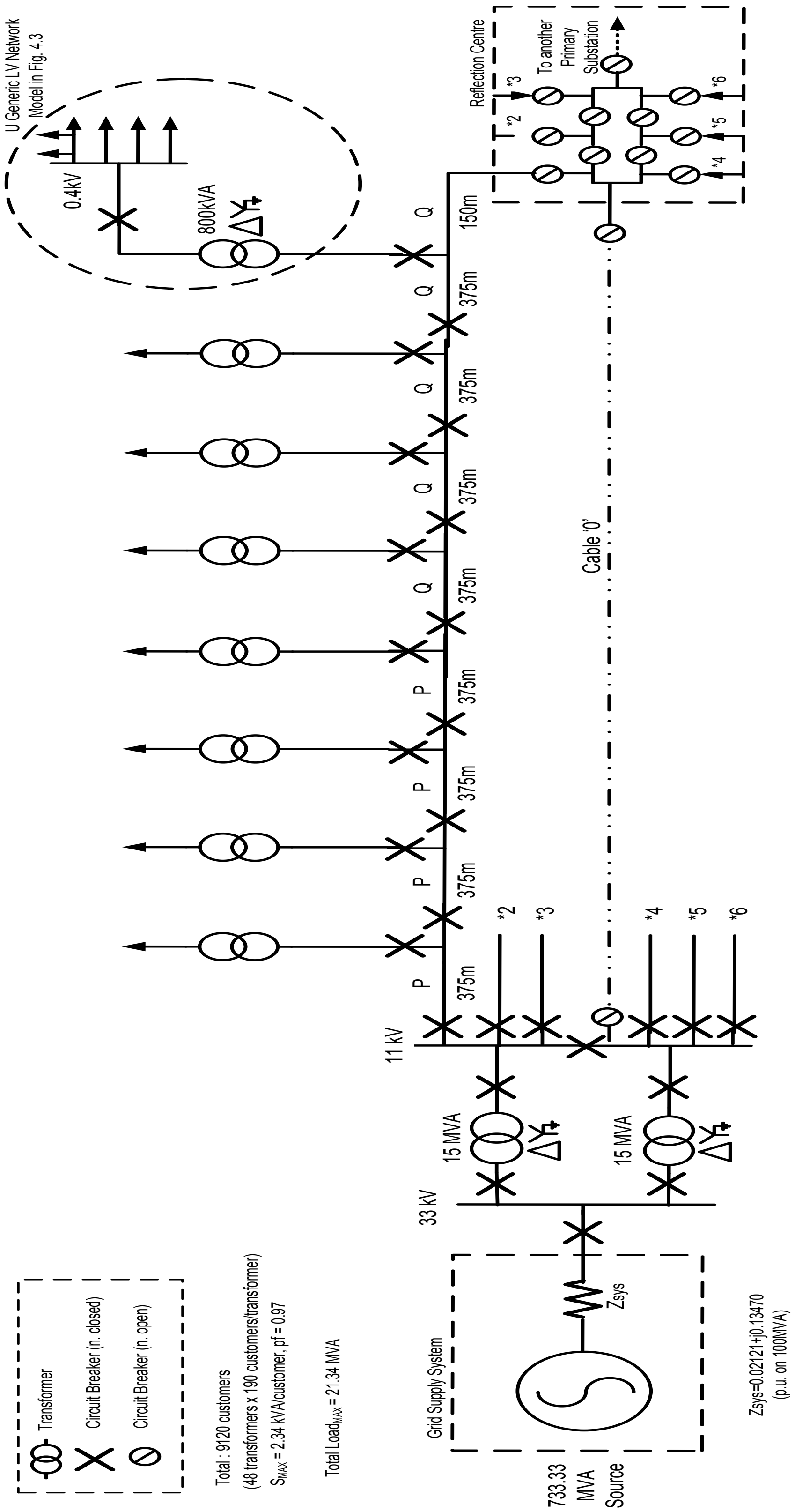


Figure 4.11: Generic MV urban network [75, 87, 89, 110, 111, 112]

Again, as in the case of HU generic MV network, the first two sections of each 11 kV feeder have higher cross-sections than the rest of the feeder due to higher loading [77, 112]. Each feeder section and head of spurs are protected by a tele-controlled circuit breaker for easy reconfiguration. Typically, two parallel 33/11 kV transformers are installed in the primary MV substation, each rated around 70% of the maximum demand. The network supplies 9,120 residential customers, has a total length and cross-section of 11 kV underground cables are: 185 mm^2 (9 km) and 95 mm^2 (9.9 km). The maximum demand (ADMD) is 20,7 MW, while minimum demand is 3,42 MW [39].

4.4.3 Sub-urban Generic MV Network Model

In smaller cities and towns, where the load demand is medium to low, the developed UK generic network model is referred as sub-urban (SU) network. Here, the network is weaker than in highly populated urban areas and is operated in radial configuration with two main feeders and normally open CBs between them. In a case of fault, the normally open CBs will close after the fault is isolated, to provide supply to all, or most of the customers. According to [77, 112], load is equally distributed (50/50) between two main feeders (made as overhead line conductors), although it is permitted to have up to 60/40 loading ratio between them.

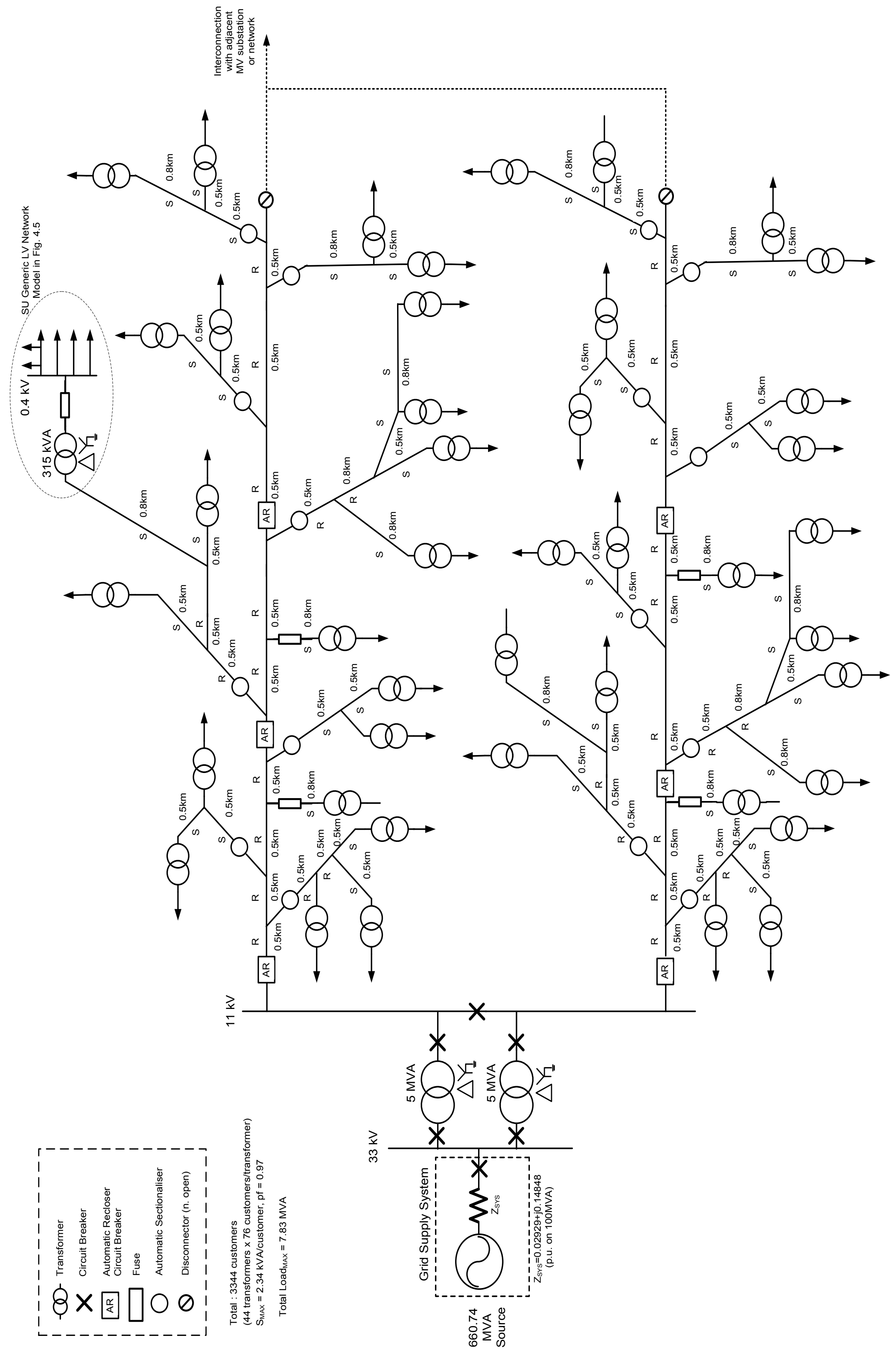


Figure 4.12: Generic MV sub-urban network [75, 89, 112, 113, 114]

As there is much larger space availability, the preferred type of substation is outdoor and mostly overhead lines are used due to lower capital and maintenance cost. In some areas, aerial cables are used to increase the reliability. The lengths of the feeders are increased, due to higher dispersion of customers, lower density of housing and increased distance from the primary MV substation. Normally, the support in form of alternative supply point is provided from the adjacent MV substation [89], as indicated in Fig. 4.12.

Two 11 kV main feeders supply a number of 11/0.4 kV load points, which usually do not have a back-up or alternative supply point. The network design includes circuit breakers, either with automatic reclosers or tele-controlled, as well as automatic sectionalisers and fuses. The allocation and the coordination of protection arrangements are based on main factors discussed in Section 4.1 [76]. Plus, as automatic sectionaliser is not preferable to be disconnected during line energising, the automatic sectionaliser must be coordinated with the circuit breaker. In other words, during a fault within the zone of the automatic sectionaliser, the main feeder circuit breaker will trip (open) and de-energise the line. During that moment, the automatic sectionaliser will open and after that, the circuit breaker will reclose. Since this network contains fuses, the fuse-saving scheme is applied. During a temporary fault originated from the fuse protection zone, the main circuit breaker will trip (open) and reclose in order to save the fuse from blowing.

The primary MV substation again has two parallel transformers, each with rating of around 70% of the total maximum (ADMD) load, supplying 3,344 residential customers (maximum demand is 7.59 MW; minimum demand is 1.25 MW [39]). The overhead line network is designed with the following total lengths and cross-sections of 11 kV OHLs: 150 mm^2 (17.1 km) and 100 mm^2 (24.4 km).

4.4.4 Rural Generic MV Network Model

The rural (R) generic MV distribution network model represents typical UK low-strength radial distribution networks supplying highly dispersed customers with low total demands. The outdoor type of substation/switchgear and overhead lines are used due to low capital and maintenance cost and as space is available for installing network components. The feeder lengths are generally long due to the increased distance of individual customers from the primary MV substation.

Within the primary MV substation, it is common to find only a single 33/11 kV transformer, which directly impacts the reliability performance of the network. The substation supplies a total of 646 rural customers, with maximum demand of 1.47 MW and minimum demand of 0.24 MW [39]. The generic rural network has the total lengths and cross-sections of 11 kV OHLs: 100 mm^2 (18.5 km) and 50 mm^2 (18 km).

In addition, this network has two main O/H feeders with a number of lateral/branch feeders. Each main feeder supplies almost the same load (53/47 ratio) and the network is equipped with various types of protection devices. The allocation and the coordination of these protection devices are again based on factors discussed in Section 4.1 [76]. Since the rural MV network is based on O/H lines and air-insulated (i.e. not enclosed) switchgear and transformers, it is vulnerable to environmental conditions (e.g. snow, wind, animal and trees), which are statistically resulting in a high number of temporary faults. Therefore, it is preferable to install ARCBs (automatic reclosing circuit breaker) with up to four reclosing attempts before the lock-out (in case of a permanent fault) [76]. This network also operates with the fuse-saving scheme as in the SU generic MV network model (Subsection 4.4.3).

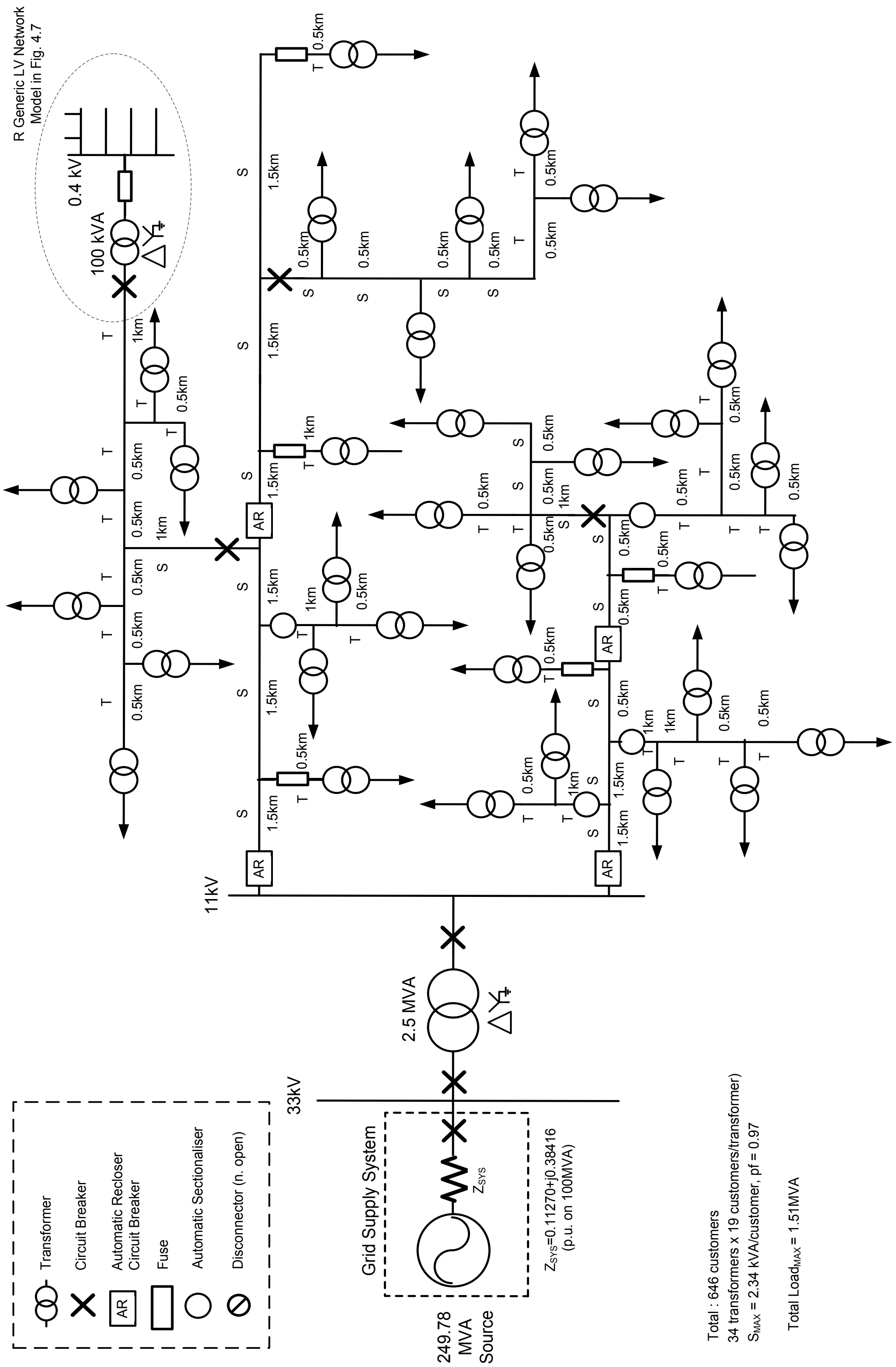


Figure 4.13: Generic MV rural network [75, 89, 112].

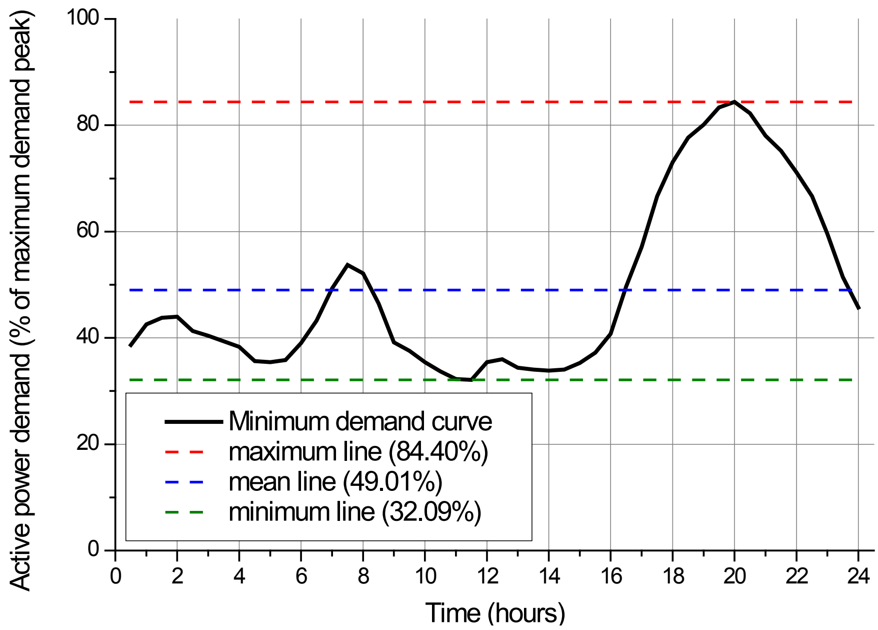
4.5 Load Profiles of Residential Customers

An important requirement in modelling and assessing reliability performance of MV and LV networks is to identify the actual demand patterns and load profiles, which are typically used as design criteria during planning (sizing of network components, allocation of network reconfiguration capabilities, etc.). Furthermore, the aggregated load profiles of, e.g., residential and commercial load sectors are widely used in power system analysis (power flow, voltage regulation, reactive power compensation, etc.) [115, 116, 117, 118, 119].

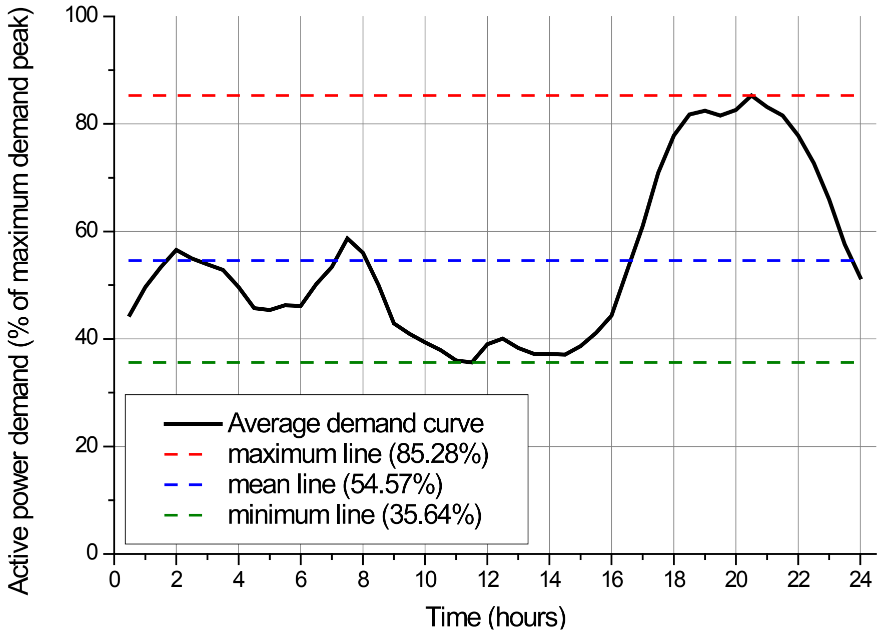
The whole process of planning and modelling presented in this thesis is based on the UK residential load sector, i.e. the considered network models are assumed to supply residential customers in their dwellings (flats, houses, etc.). Therefore, two sets of data are required for the reliability assessment: load curves, with detailed information on variations of active and reactive power demands over the considered time period, as well as statistical information on different load types contributing to the total load demand.

4.5.1 Residential Load Curves

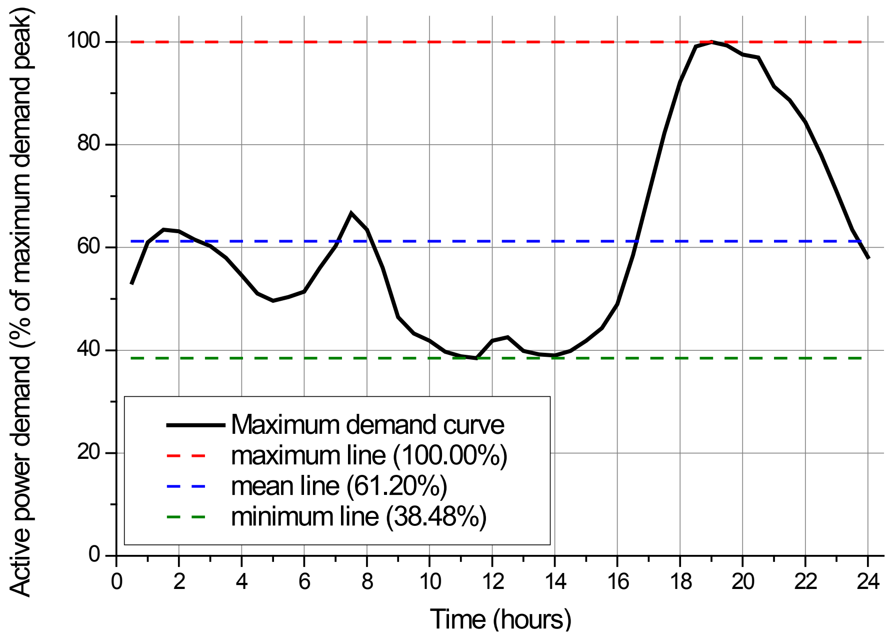
According to [120], the typical aggregate load curves of the UK residential load sector are shown in Figure 4.14, which represent the overall UK residential sector demand. However, as the urban subsector accounts for more than 50% of the residential demand [121], this subsector can be considered as the representative of the overall UK residential load demand. The curves in Figures 4.14 show the three typical loading conditions, i.e. seasonal variations in demand over the course of the year. Accordingly, each curve can be allocated to a specific season, e.g., the maximum loading conditions correspond to the winter demand. However, the general shape of the three load curves is very similar, as the behaviour of the users does not change significantly throughout the year (with only exceptions being somewhat higher demand during the night due to "economy 7" customers utilising electrical heating loads in winter). The recorded seasonal variations are the result of changing contributions from actual customers' loads, i.e. loads that respond to changes in ambient condition (temperature, solar irradiance, etc.). Therefore, it is expected to have increased or decreased contributions of specific load types in different seasons, for example, mentioned increase of electric space and water heating loads during the winter season.



(a) Minimum demand curve [120]



(b) Average demand curve [120]



(c) Maximum demand curve [120]

Figure 4.14: Active power demand of residential load

Based on [77, 112], the after diversity maximum demand (ADMD) of residential customers is estimated between 2 kW and 3 kW, depending on whether gas-heating or electrical heating is used in dwellings (approximately 19% of all UK households have "economy 7" tariff, which suggests use of electrical heating load). The average power factor value of 0.97 is assumed for all analysis in this thesis. From [87], the load demand figures show that the maximum and the minimum demands were 1.3 kVA and 0.16 kVA respectively. However, the analysis in this thesis considers minimum demand of 0.375 kW and 2.27 kW for maximum loading conditions, with power factor of 0.97, as suggested in [39]. Although the considered values are almost twice higher than in [87], it is assumed that this presents a 'worst case' scenario, enabling for analysis of future upgrading of network models, including connection of DG, new customers, etc. Additionally, the maximum loading condition value (2.27 kW) is considered suitable, as it is between 2 kW and 3 kW (see [77, 112] for more detail).

Accordingly, each of the secondary 11/0.4 kV substations in the analysed generic network models supplies between 50% and 60% of the maximum demand (obtained from equal contributions of all customers), in order to avoid overloading of the transformers. As previously stated, the reason for the 50%-60% maximum load is selected to accommodate for the future expansion of the network with 1%-2% annual increase of load and for the provision of alternative supply capabilities [73].

4.6 Chapter Summary

This chapter presents the generic models of medium and low voltage distribution networks for the four main residential load subsectors. The presented classification of these subsectors is based on the location, size, geographic dispersion and few other important characteristics of the corresponding residential types of customers and their typical dwellings. For that purpose, a comprehensive database of specifications, characteristics and parameters of LV and MV distribution networks, network components, configurations and applied types and settings of protection systems is developed and used for modelling. Importantly, the LV distribution networks are modelled with a full three-phase model, rather than single-line representation, in order to realistically reproduce the actual network operating conditions.

Particular attention was given to the identification of protection devices (circuit breaker, reclosers, sectionalisers and fuses), as well as to their settings and principles of operation, as this is very important for the analysis of short and long supply interruptions in cases of different types of faults. Additionally, automatic and remote control functionalities in MV networks, together with the provision of alternative supply points are all considered (e.g. in terms of N-1 security requirements in MV networks, where load densities are high and it is likely to install two parallel transformers). For subsectors where the load densities are low, a single transformer is installed within the 33/11 kV substation.

The four generic residential subsectors are modelled in detail with the corresponding HU, U, SU and R network models, where each subsector is represented with both

MV and LV networks. For example, fuses and circuit breakers are most commonly used protection devices, but previous work did not provide clear identification of typical implementations in considered types of the LV and MV networks. Therefore, this thesis provides detailed descriptions of protection devices/systems in all generic networks, as well as the implementation of two general protection schemes (fuse-saving and fuse-blowing, where fuse-saving is primarily used for reducing impact of temporary faults, while fuse-blowing for reducing impact of permanent faults). Although there are no publicly available guidelines on DNOs practices for using fuse-saving and fuse-blowing schemes, these are again analysed for each of the generic subsectors.

Finally, another important aspect of modelling and assessing reliability performance of MV and LV networks is analysed in this chapter: incorporation of actual demand patterns and load profiles into the analysis. This is represented with the three main loading conditions (minimum, average and maximum demands), based on the change of seasons throughout the year. Accordingly, maximum loading conditions correspond to winter, minimum conditions to summer and average conditions to spring and autumn. All these results are used in the next chapters for the calculation and comparison of reliability performance of different scenarios and operating conditions of the four generic LV and MV distribution network models.

Chapter 5 Reliability Equivalents of Generic LV Distribution Networks

This chapter discusses formulation of the more detailed reliability equivalents of the four generic LV distribution network models (developed in Chapter 4) for improved reliability assessment. The required input data (fault rates and repair times), the distinction between the different fault types (permanent vs. temporary, as well as single-, double- and three-phase), the use of different protection devices (single-pole vs. three-pole) and some other important aspects are discussed, evaluating their importance for the reliability assessment. The results are presented for different sizes of the modelled generic networks, based on the typical ratings of transformers in secondary distribution substations.

During the standard reliability performance analysis of medium voltage (MV) and high voltage (HV) networks, downstream connected low voltage (LV) networks are typically not represented in much detail. The two main reasons for that are: a) a general lack of accurate information on LV network configurations (particularly service entry connections of LV customers), applied LV protection systems and actual fault rates and repair times of LV network components, and b) a significant increase in complexity of calculations, leading to excessive computational requirements and long simulation times, if LV networks with a large number of components are included in the analysis. Consequently, as the analysis proceeds from lower voltage levels to higher voltage levels (i.e. to the analysis of larger networks), more and more LV network components have to be included. Particularly important is representation of the new and emerging network components connected at LV levels, such as energy storage, microgeneration and demand-side manageable loads, as these might have strong impact on the actual reliability performance of analysed networks at all voltage levels. Nevertheless, in standard reliability analysis, LV networks are usually represented using some "equivalent form" [39, 87, 134, 135, 136, 137], instead of a more detailed (reliability) model.

The most common equivalent form representation of LV networks is by a simple aggregate ("lumped") load, specifying number of supplied customers and their peak active and reactive power demands (and sometimes minimum, or average demands, or daily load profiles) downstream of the MV point of aggregation, which is typically a primary or secondary distribution substation or transformer. Another common assumption is that most of the permanent faults resulting in long interruptions (LIs) of supply occur in MV networks, e.g. [128, 138, 139]. However, the contributions of the LV networks to the overall system reliability performance in terms of frequency and, particularly, duration of LIs could be significant, although permanent LV faults (the main cause of unplanned LIs) usually do not result in the interruptions of a large number of customers.

In order to address the abovementioned issues related to the correct modelling and representation of LV networks, and following the formulation of the four generic LV and MV network models from Chapter 4, this chapter discusses and illustrates how more detailed and more accurate "reliability equivalent models" can be derived for the considered LV networks, which then can be directly implemented for the analysis of MV (and HV) networks. This is followed by the analysis of the ongoing and anticipated changes in the operation of modern networks in Chapter 6, which discusses modelling of LV networks with distributed and micro generation (DG/MG) and energy storage (ES).

5.1 Input Data for Reliability Analysis

Correct assessment of reliability performance strongly depends on the availability and accuracy of the required input data, where of the highest importance are mean fault rates and mean repair times (or mean unavailability) of the network components in the analysed networks. This is acknowledged in the available literature, reports and statistics, as mean fault rates and mean repair times are the most common data used both as inputs for the reliability analysis and as outputs for presenting or comparing reliability performance of different networks (e.g. [25], [122], [123] and [46]). However, as discussed in the previous chapters and as will be shown in the further text, some additional input data are required for the analysis of unplanned supply interruptions.

The first additional data are percentage contributions of temporary (i.e. transient or momentary) faults and permanent (i.e. sustained) faults to the total (annual) number of faults, as this usually allows to make distinction between short and long supply interruptions (i.e. supply interruptions shorter or longer than 3 minutes). The second additional input data are percentage contributions of different types of the faults (i.e. single-, double- or three-phase faults) to the total (annual) number of faults, as this usually defines the requirements for modelling analysed networks in terms of single-line or three-line diagrams, due to the use of single-pole or three-pole protection (fuses vs. circuit breakers), as discussed in Chapter 4. Finally, this thesis introduces type of the network, or type of the load (sub)sector, as the additional data required for the analysis. All that is discussed in the further text.

5.1.1 Mean Fault Rates and Mean Repair Times

As mentioned, the most-common input data for reliability analysis are mean fault rates and mean repair times of network components. Most of the available statistics, however, give these data only for components operating at specific voltage levels and provide no further information as to how the corresponding values change in different networks. Without that information, it is not possible to assess the variations in reliability performance of LV and MV networks supplying customers in highly-urban, urban, sub-urban and rural areas and, subsequently, to formulate their equivalent models for the analysis of sub-transmission and transmission networks.

Tables 5.1 and 5.2 present the statistics on the mean fault rates and mean repair times obtained from the three main sources: Energy Network Association (ENA) report [124], Scottish Power Distribution (SPD) [105, 125, 126], and other sources [8, 122, 123, [127, 128, 129, 130, 131, 132]. ENA statistics were obtained as part of the UK National Fault and Interruption Reporting Scheme (NaFIRS), to which all DNOs in the UK send their annual reliability statistics, while SPD is one of the two DNOs in Scotland, for which detailed statistics on fault rates and repair times were available for one calendar year. The “other sources” represent data that are found after an extensive survey of available literature, reports, and statistics from other countries.

The last column (“selected value”) in Tables 5.1 and 5.2 lists the values assumed in this thesis as the most representative for the analysis of the UK/Scottish generic networks, which are mostly based on the statistics from the UK-based reports [124] and [105], [125], [126]. Footnotes for both tables explain that in some cases data from other sources are used as the more realistic values and that for components with no information in [124] or [105], [125], [126], average value from the other sources is assumed. In a few cases when only one value was available, this value is used.

The following example illustrates the selection of the final value outside of the ENA report: the ‘urgent’ repair time, corresponding to faults resulting in customer supply interruptions, of 33/11kV transformer based on the ENA report is 205.5 hours (equivalent to 8.6 days), while ‘non-urgent’ repair time, referring to repair time of the faulted network component that does not result in customer supply interruption (e.g. due to redundancy of the components), is 545.6 hours (equivalent to 22.7 days),. The urgent repair time of 33/11kV transformer reported in SPD and other references is much lower, around 100 hours, so the value from SPD statistics is selected for the analysis presented in the thesis.

Table 5.1: Mean fault rates for LV and MV network components

Component	kV	Fault rate (fault/year)		Final selection
		ENA [124]	Other sources [8], [122], [123], [127]–[132]/ SPD [105], [125], [126]	
Transformer	33/11	0.01	0.009[127], 0.015[8] (0.009-0.012-0.015) 0.6597(SPD)	0.01
	11/0.4	0.002	0.015[8], 0.01[122], 0.01[128], 0.0096[129], 0.0096(S)[123], 0.0079(N)[123], 0.012(D)[123] (0.0079-0.0106-0.015) 0.1809(SPD)	0.01[1]
Bus bar	33	-	0.001[8]	0.001
	11	-	0.005[130], 0.001[8] (0.001-0.003-0.005)	0.003
	0.4	-	0.005[130]	0.005
Overhead Line (per km)	33	0.034	0.046[8], 0.0075[131] (0.0075-0.0268-0.046)	0.034
	11	0.091	0.065[8], 0.123[122], 0.05[128], 0.0189[131], 0.1115(S)[123], 0.0372(N)[123], 0.0379(D)[123], 0.0477(F)[123] (0.0189-0.0614-0.123)	0.091
	0.4	0.168	0.383[122], 0.09(S)[123] (0.09-0.2365-0.383) 0.0706(SPD)	0.168
Underground Cable (per km)	33	0.034	0.044[127], 0.00336[131] (0.0034-0.0237-0.044)	0.017[2]
	11	0.051	0.046[127], 0.005[130], 0.04[8], 0.019[122], 0.02[128], 0.00617[131], 0.0236[129], 0.0197(S)[123], 0.0244(N)[123], 0.0238(D)[123], 0.0085(F)[123] (0.005-0.0215-0.046)	0.051[3]
	0.4	0.159	0.03[122], 0.00388[131] (0.0039-0.0170-0.03) 0.1182(SPD)	0.1182[4]
Circuit Breaker	33	0.0041	0.002[8]	0.0041
	11	0.035	0.005[130], 0.006[8], 0.011[129], 0.011(S)[123], 0.0025(N)[123] (0.0025-0.0071-0.011)	0.0071[5]
	0.4	-	0.005[130], 0.02[128], 0.00201[132] (0.0020-0.0090-0.02)	0.0071[6]
Fuse	11	0.0004	0.011[122], 0.003[129] (0.003-0.007-0.011)	0.007[7]
	0.4	-	0.004[122], 0.00137[132] (0.0014-0.0027-0.004) 0.0591(SPD)	0.0027[8]
Sectionaliser	11	0.034	0.0025[123], 0.002[129] (0.002-0.00225-0.0025)	0.0071[9]

Where S=Sweden, D=Denmark, F=Finland and brackets give (minimum-average-maximum) values found in other sources.

[1] Most of the values from the other sources were around 0.01.
[2] Based on [131], fault rates for 33 kV cables are 1/2 of 33 kV overhead lines values.
[3] Based on [8], [123], fault rates for 11 kV cables are 2/3 of 11 kV overhead lines.
[4] Based on [122], fault rates for 11kV cables are around twice higher than for 0.4kV cables (SPD value).
[5] Average value from other sources is around 0.007.
[6] Based on [130], fault rates were same for 11kV and 0.4kV circuit breakers.
[7] ENA values were too low compared to the other sources.
[8] Based on [122], fault rate for 0.4kV was 1/3 of 11kV fuse.
[9] Based on [124], fault rates for circuit breakers and sectionalisers are similar, so these are changed, too.

Table 5.2: Mean repair times for LV and MV network components (U-urgent repair time, for faults resulting in supply interruptions; NU-non-urgent repair time, for faults not resulting in supply interruptions)

Component	kV	Mean Time To Repair (hours/fault)			Final selection	
		ENA [124]		Other sources [8], [122], [123], [127]–[132]/ SPD [105], [125], [126]		
		U	NU		U	NU
Transformer	33/11	205.5	545.6	120[8] 100.12(SPD)	100.12[10]	545.6
	11/0.4	75	515.6	200[8], 8.7[122], 5[128] (5.00-71.23-200.00) 19.82(SPD)	19.82[11]	515.6
Bus bar	33	-	-	8[8]	8	
	11	-	-	120[130], 8[8] (8.00-64.00-120.00)	8	
	0.4	-	-	24[130]	4[12]	
Overhead Line	33	18.8	95.2	8[130], 8[131]	18.8	95.2
	11	7.1	191.3	5[130], 25[122], 6[128], 4.6[131] (4.60-10.15-25.00)	7.1	191.3
	0.4	5.7		80.2[122], 6.44(SPD)	5.7	
Underground Cable	33	201.6	338.4	16[131]	37.6[13]	338.4
	11	56.2	256.9	48[130], 30[8], 8.5[122], 5.9[128], 20.4[131], 118.69[129] (5.90-38.58-118.69)	13.0[14]	256.9
	0.4	6.9		6.2[122], 26.8[131] (6.20-16.50-26.80) 5.37(SPD)	6.9	
Circuit Breaker	33	140	158.1	96[8]	96	158.1
	11	120.9	801.4	48[130], 72[8] (48.00-60.00-72.00)	72	801.4
	0.4	-	-	36[130], 4[128], 11.22[132] (4.00-17.07-36.00)	36[15]	
Fuse	11	35.3	385.4	4.2[122]	4.2[16]	385.4
	0.4	-	-	2.6[122], 4[132] (2.60-3.30-4.00) 3.04(SPD)	3.04[17]	
Sectionaliser	11	36.2	559.5	-	36.2	559.5

Where brackets give (minimum-average-maximum) values found in other sources.

[10] SPD value is close to the only available value from other sources.
[11] SPD value had been the only value close to the two values from the other sources.
[12] In [130], 0.4kV busbar repair times was 1/5 of 11kV busbar repair times; it is impossible to replace within 1.6 hours, at least 4 hours is reasonable.
[13] Double the value of repair times, when compared for 33kV O/H lines and 33kV U/G cables, [131].
[14] Based on [122], 11kV cable repair times were around three times lower than 11kV lines repair times.
[15] 33kV CB took 4 days, while 11kV CB took 2-3 days to repair. Therefore, it is reasonable that 0.4kV CB repair time is around 36 hours (maximum value from other sources).
[16] Value of 35.3 hours is much longer repair time than the value suggested in the UK Guaranteed Standard of Performance value; 3-4 hours is selected [108].
[17] Close to the mean value from all other sources.

Mean fault rates and mean repair times of components in Tables 5.1 and 5.2 are given for specific voltage levels, with no distinction between networks in different areas, e.g. LV or MV networks supplying urban and rural residential customers. In existing literature, some European DNOs provide SAIFI and SAIDI statistics for urban (U), sub-urban (SU) and rural (R) areas, while one Australian DNO also provides data for highly-urban (HU) areas. This is illustrated in Table 5.3, which shows that the network reliability performance in terms of both SAIFI and CAIDI indices in almost all cases improves from rural, through sub-urban and urban, to highly-urban areas. The values from Table 5.3 are used to calculate coefficients for estimating how mean fault rates and repair times change in different types of the networks, (5.1)-(5.4), with Table 5.4 showing disaggregated values for four UK generic residential sub-sectors.

$$A1_i = \frac{Average_i}{Average\ of\ HU,\ U,\ SU\ and\ R} \tag{5.1}$$

$$A2_i = \frac{Average_i}{Average\ of\ HU\ and\ U} \tag{5.2}$$

$$A3_i = \frac{Average_i}{Average\ of\ SU\ and\ R} \tag{5.3}$$

$$A4_i = \frac{Average_i}{Average\ of\ HU,U\ and\ SU} \tag{5.4}$$

where: i denotes HU, U, SU or R load sectors. A1 denotes network components found in all four generic sub-sectors (e.g. transformers), A2 denotes network components found only in HU and U sub-sectors (e.g. 33kV and 11kV cables), A3 denotes components found only in SU and R sub-sectors (e.g. 11kV fuses), while A4 denotes components found in HU, U and SU sub-sectors (e.g. LV cables).

Table 5.3: Fault rate and repair time coefficients for the disaggregation in four generic residential load subsectors

<table>
<tr><th rowspan="2">Indices</th><th rowspan="2" colspan="2">Recorded statistics</th><th rowspan="2">HU</th><th rowspan="2">U</th><th rowspan="2">SU</th><th rowspan="2">R</th><th colspan="4">Average</th></tr>
<tr><th>HU, U, SU and R</th><th>HU and U</th><th>SU and R</th><th>HU, U and SU</th></tr>
<tr><td rowspan="14">SAIFI</td><td colspan="2">Norway[15]</td><td colspan="2">0.9</td><td>1.50</td><td>2.70</td><td rowspan="9" colspan="4">-</td></tr>
<tr><td colspan="2">Finland[46]</td><td colspan="2">0.27</td><td>0.89</td><td>4.20</td></tr>
<tr><td colspan="2">Australia[16], [133]</td><td>0.07</td><td>1.45</td><td>2.40</td><td>4.47</td></tr>
<tr><td colspan="2">France[14]</td><td></td><td>0.73</td><td>0.91</td><td>1.37</td></tr>
<tr><td colspan="2">Italy[14]</td><td colspan="2">1.48</td><td>2.27</td><td>3.23</td></tr>
<tr><td colspan="2">Portugal[14]</td><td colspan="2">1.61</td><td>2.47</td><td>4.33</td></tr>
<tr><td colspan="2">Romania[14]</td><td colspan="2">4.20</td><td colspan="2">9.75</td></tr>
<tr><td colspan="2">Slovenia[14]</td><td colspan="2">0.64</td><td>1.37</td><td>1.97</td></tr>
<tr><td colspan="2">Spain[14]</td><td colspan="2">1.56</td><td>2.34</td><td>3.42</td></tr>
<tr><td colspan="2">Average of recorded statistics</td><td>1.27</td><td>1.43</td><td>2.66</td><td>3.94</td><td>2.32</td><td>1.35</td><td>3.30</td><td>1.78</td></tr>
<tr><td rowspan="4">Mean fault rates coefficient</td><td>A1</td><td>0.55</td><td>0.61</td><td>1.14</td><td>1.70</td><td rowspan="4" colspan="4">-</td></tr>
<tr><td>A2</td><td>0.94</td><td>1.06</td><td>-</td><td>-</td></tr>
<tr><td>A3</td><td>0.71</td><td>0.80</td><td>1.49</td><td>-</td></tr>
<tr><td>A4</td><td>-</td><td>-</td><td>0.81</td><td>1.19</td></tr>
<tr><td rowspan="14">CAIDI</td><td colspan="2">Norway[15]</td><td colspan="2">1.20</td><td>2.80</td><td>5.10</td><td rowspan="9" colspan="4">-</td></tr>
<tr><td colspan="2">Finland[46]</td><td colspan="2">0.62</td><td>0.93</td><td>0.85</td></tr>
<tr><td colspan="2">Australia[16], [133]</td><td>3.00</td><td>1.61</td><td>1.47</td><td>2.37</td></tr>
<tr><td colspan="2">France[14]</td><td colspan="2">0.80</td><td>0.84</td><td>1.21</td></tr>
<tr><td colspan="2">Italy[14]</td><td colspan="2">0.55</td><td>0.59</td><td>0.61</td></tr>
<tr><td colspan="2">Portugal[14]</td><td colspan="2">0.88</td><td>0.89</td><td>1.00</td></tr>
<tr><td colspan="2">Romania[14]</td><td colspan="2">1.26</td><td colspan="2">1.76</td></tr>
<tr><td colspan="2">Slovenia[14]</td><td colspan="2">0.82</td><td>0.69</td><td>0.67</td></tr>
<tr><td colspan="2">Spain[14]</td><td colspan="2">0.68</td><td>0.77</td><td>0.95</td></tr>
<tr><td colspan="2">Average of recorded statistics</td><td>1.09</td><td>0.94</td><td>1.19</td><td>1.61</td><td>1.21</td><td>1.01</td><td>1.40</td><td>1.07</td></tr>
<tr><td rowspan="4">Mean times to repair coefficient</td><td>A1</td><td>0.90</td><td>0.77</td><td>0.99</td><td>1.34</td><td rowspan="4" colspan="4">-</td></tr>
<tr><td>A2</td><td>1.08</td><td>0.92</td><td>-</td><td>-</td></tr>
<tr><td>A3</td><td>1.02</td><td>0.87</td><td>1.11</td><td>-</td></tr>
<tr><td>A4</td><td>-</td><td>-</td><td>0.85</td><td>1.15</td></tr>
</table>

The reported SAIFI and CAIDI values in Table 5.3 are based on related number of customers, frequency and duration of interruptions. In other word, for example, HU SAIFI and CAIDI values are based on the frequency and duration of interruptions experienced by the total number of customers within the coverage area of the HU subsector, not total number of customer from all sectors (HU, U, SU and R). The first step of calculation of coefficients is averaging all recorded values by its subsectors. For example, in SAIFI of R sector, by averaging all values of R sector, the result is 3.94. The second step is selecting the type of component available in each subsector. For example, circuit breakers are available in all four HU, SU, U and R sectors, while overhead lines are is available only in SU and R sectors. For all sectors (HU, U, SU and R) column, the average of all values in 'average of recorded statistics' (1.27, 1.43, 2.66 and 3.94), is 2.32. The final step is calculation of the mean coefficient by dividing average value of recorded statistics of each subsector with 2.32. For example in A1 (HU), 1.27 divided by 2.32, give the result 0.55.

Table 5.4: Final fault rates and repair times for four generic UK load sub-sectors.

Component	kV	Fault rates (fault/year)				Repair times (hours/fault)			
		HU	U	SU	R	HU	U	SU	R
Transformer	33/11	0.0055	0.0061	0.0114	0.0170	94.12	93.12	99.12	102.12
	11/0.4	0.0055	0.0061	0.0114	0.0170	14.62	13.62	19.62	22.62
Bus bar	33	0.0006	0.0006	0.0011	0.0017	7.16	6.16	12.16	15.16
	11	0.0017	0.0018	0.0034	0.0051	7.16	6.16	12.16	15.16
	0.4	0.0028	0.0031	0.0057	0.0085	4.08	3.08	9.08	12.08
Overhead Lines per km	33			0.0275	0.0405			17.98	21.62
	11			0.0737	0.1083			6.04	8.17
	0.4			0.1361	0.1999			4.85	7.85
Underground Cable per km	33	0.0160	0.0180			35.59	34.59		
	11	0.0479	0.0541			12.96	11.96		
	0.4	0.0839	0.0946	0.1761		7.04	6.00	7.66	
Circuit Breaker	33	0.0023	0.0025	0.0047	0.0070	90.04	89.04	95.04	97.04
	11	0.0039	0.0043	0.0081	0.0121	66.28	65.28	71.28	74.28
	0.4	0.0039	0.0043	0.0081	0.0121	30.64	29.64	35.64	38.64
Fuse	11			0.0057	0.0083			3.00*	3.00*
	0.4	0.0015	0.0016	0.0031	0.0046	3.00*	2.34	3.00*	3.00*
Sectionalizer	11			0.0057	0.0083			30.77	41.63

Where * is repair time limit by 3 hours (GSP requirement).

From Table 5.3, the available statistics only give SAIFI values, which correspond to long interruptions, while there was no information on MAIFI (short interruptions). The two most likely reason are that there is still no obligation to report statistics on short interruptions, or simply that MAIFI data are not publicly reported. Accordingly, it is assumed in this thesis that the coefficient for calculating MAIFI is the same as the SAIFI coefficient and all statistics are averaged into the related single values and changed into coefficient values in order to adequately modify the final selection from Tables 5.1 and 5.2. Although the MAIFI coefficient is assumed the same as the SAIFI coefficient, the final result is different due to incorporating LI/SI ratio (Table 5.5) in the simulation/calculation process. This is illustrated in Table 5.4, which shows the final mean fault rates and mean repair times allocated to the four generic subsectors. Again, some of the values are adjusted based on the requirement of the UK Regulator, representing, for example, the additional access times due to traffic conditions in dense downtown city areas, or the longer travelling distances to rural areas, where average access and repair time are also longer due to weather conditions (e.g. strong wind, rain and snow).

5.1.2 Types of Faults

The reliability performance of power supply systems is quantified through a series of indices corresponding to long interruptions (LIs) and short interruptions (SIs) of supply, where unplanned LIs occur mainly due to permanent faults, while SIs occur both due to transient faults and due to permanent faults, for which application of fault response and fault isolation schemes successfully prevented LIs by, e.g. network reconfiguration, or switching to alternative supply points.

It is a commonly known fact that overhead rural network have significantly higher number of SIs than number of LIs, while the opposite is true for underground urban networks. However, it is generally not possible from available statistics and reports on actual DNOs' performance to make a clear distinction between the numbers of LIs and SIs in different types of the networks. For example, using available OFGEM statistics for 14 UK DNOs [6, 14], it is possible to identify that 46% of all supply interruption events in all distribution networks and at all reported voltage levels were LIs (caused by permanent faults), while 54% were SIs (caused by transient/temporary faults).

Although this allows to have a general idea about the overall percentage contributions of both types of supply interruptions, further segregation into different areas/types of networks (e.g. urban vs. rural network) is not possible. After another extensive review of available literature, it was found that only three DNOs (from Finland, France and Italy) reported statistics for LIs and SIs in urban (U), sub-urban (SU) and rural (R) networks, Table 5.5.After careful examination of these DNO data, statistics from Finland were not taken in to account for calculating average values (the last column in Table 5.5), due to much higher reported values than in the reports of two other DNOs. As none of the DNOs statistics lists values for LIS and SIs in their highly-urban (HU) networks, the highest reported urban (U) value for LIs was assumed for HU networks (which also determined percentage contribution of SIs).

Table 5.5: Available DNOs' statistics on long and short supply interruptions in different types of networks, [15, 18].

LI/SI Ratio	Voltage level	Finland [46]	France[14]	Italy[14]	Average
LI	MV/LV	U=87 SU=81 R=78	U=48 SU=34 R=23	U=40 SU=28 R=25	HU=48 U=44 SU=31 R=24
SI	MV/LV	U=13 SU=19 R=22	U=52 SU=66 R=77	U=60 SU=72 R=75	HU=52 U=56 SU=69 R=76

After obtaining the final fault rates and repair times of four generic UK load sub-sectors for every component (Table 5.4), these values are incorporated with the LI/SI ratio based on the related subsector. For example, in Table 5.4, in column fault rates for R sector, the value for overhead lines per km for 0.4 kV is 0.1999 fault/year. By applying LI/SI ratio of 24% is LI and 76% is SI, the final fault rates of overhead lines per km for 0.4 kV are 0.0480 LI per year and 0.1519 SI per year.

5.2 Generic LV and MV Equivalent Network Models

Typically, the LV network is represented using limited information, specifying number of customers, maximum active and reactive power demands. This results in high uncertainties and errors in estimated reliability performance, as the input data (fault rates and repair times) are not properly disaggregated based on the actual network components and parameters. Therefore, formulating accurate equivalent networks will result in a more confident assessment of reliability performance.

5.2.1 Significance of including LV Equivalents in the Analysis

This sub-section illustrates the importance of including correct models and equivalent representations of LV networks in the reliability analysis of MV and HV networks. As an example, a one-year statistics for one DNO in the UK (Scottish Power Distribution, SPD) is shown in Figs. 5.1 and 5.2.

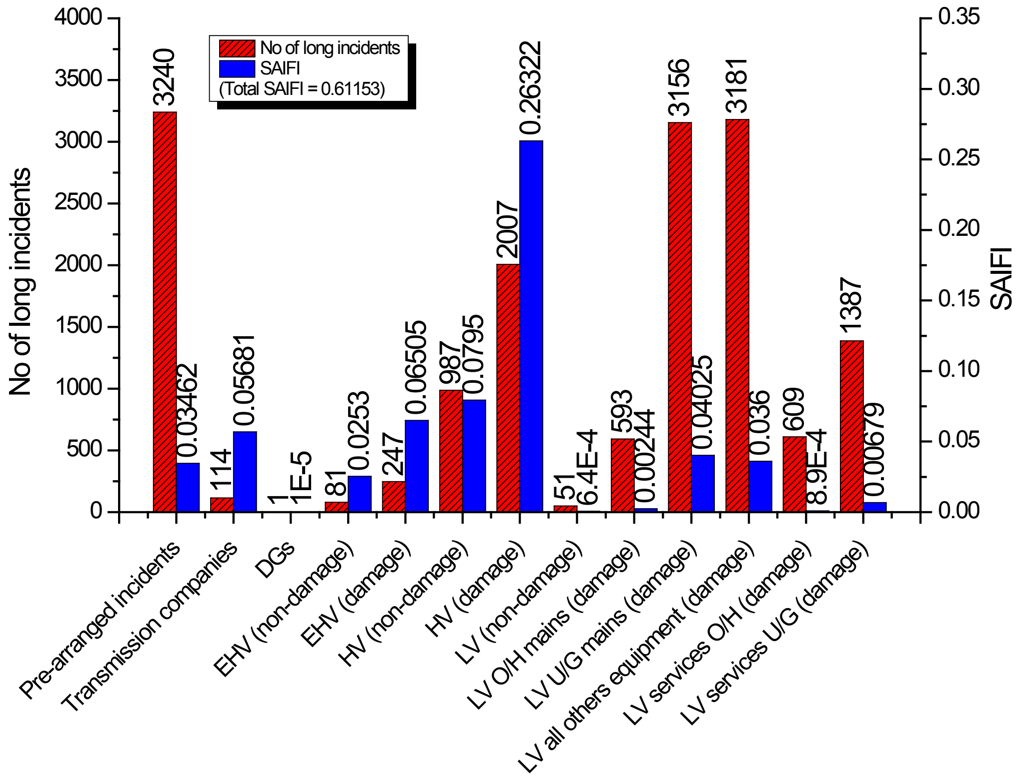


Figure 5.1: Number of permanent faulted components and SAIFI index [126].

It can be seen from Fig. 5.1 that most of the permanent faults of network components resulting in LIs of customers occurred in LV networks (significantly higher number than in 11kV and, particularly, 33kV MV networks). The SPD provides energy to almost two million customers in Scotland, of which the vast majority are connected to LV networks (e.g. residential and small commercial customers). This clearly illustrates the importance of taking into account configurations, network components and protection systems in LV networks, although the contribution of faults/LIs in LV networks to the total SAIFI values is lower than the contribution of faults/LIs in MV networks (because a fault in MV networks results in higher number of disconnected customers than a fault in LV networks). Accordingly, the impact of faults/LIs in LV networks on the total SAIDI values is higher, as the number of actually interrupted customers has no influence on the calculation of the SAIDI index.

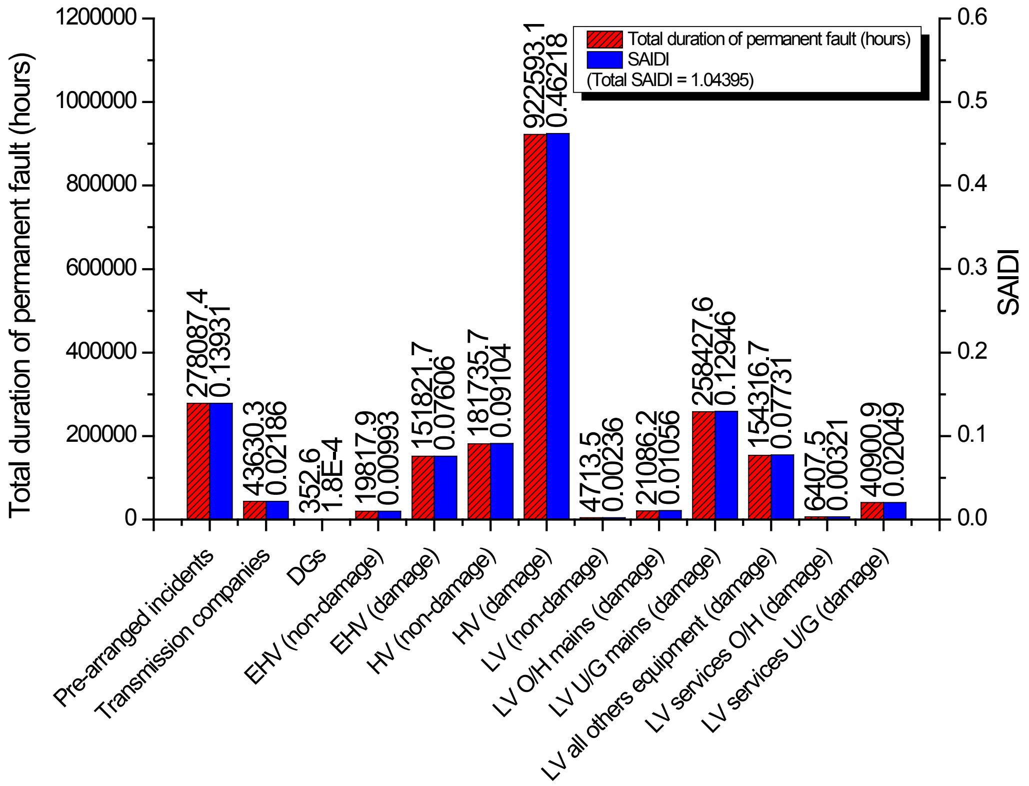


Figure 5.2: Total duration of permanent faulted components and SAIDI index [126].

5.2.2 Formulation of LV Network Equivalents

The formulation of accurate reliability equivalent models of the four generic LV networks from Chapter 4 (corresponding to the four load subsectors, HU, U, SU, and R) requires detailed modelling of network configurations, parameters, characteristics (e.g. protection systems) and fault conditions (e.g. types of faults). This is illustrated in this and further sub-sections, where the main motivation is to allow for a more comprehensive QoS/reliability analysis and, consequently, for a higher confidence in the obtained results of the reliability assessment.

The presented methodology for the formulation of reliability network equivalents reduces analysed LV network (typically operating in radial configuration) to a single "equivalent network" component. This allows to achieve short computational times (as only one component is used to represent the whole LV network), but requires accurate calculation of the equivalent mean fault rates and mean repair times of that single-equivalent component. Basically, the methodology is applying a bottom-up (or reverse) approach, beginning at the individual customer level (i.e. customer supply points, CSPs), then going through secondary (LV) distribution substations, all the way up to the primary (MV) distribution substations, where aggregate/equivalent demands and lumped/equivalent representations of the modelled networks are typically connected.

The main challenges in modelling MV and, particularly, LV distribution networks are large numbers of various network components, complex and dispersed network structures and variations in applied protection systems, which all lead to the difficulties in devising fast and accurate methodologies for evaluation of network reliability performance. A number of techniques have been developed to simplify the calculation and reduce the complexity of the modelled networks, i.e. to reduce the computational times. The most common techniques that had been previously applied to quantify reliability network performance were: approximate method, network reduction method and failure modes and effects analysis (FMEA) method [140, 141, 142, 143].

The approximate method requires to select the priority of the network components that needs to be modelled/equivalented, which generally depends on the configuration of the network and on the location of the component in the network. For each group of the components, i.e. a sub-equivalent network, a set of equations needs to be established, based on the size of the sub-equivalent network.

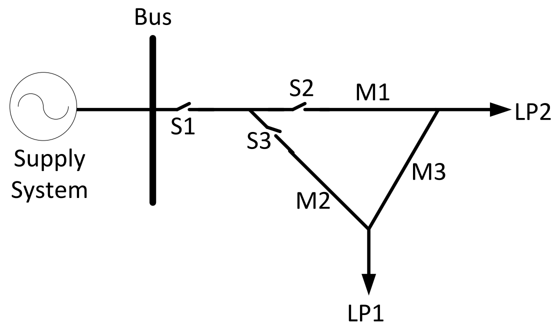


Figure 5.3: Example of a "triangle-shaped" network configuration.

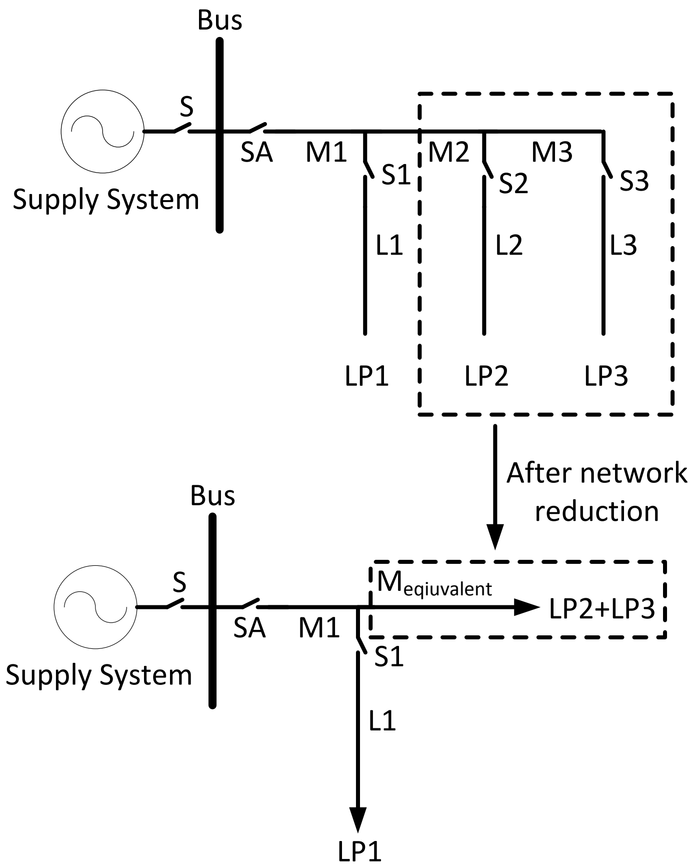


Figure 5.4: Example for illustrating network reduction technique.

The network reduction technique reduces the network sequentially, or in steps, by using the appropriate equations for both series- and parallel-connected combinations of components, typically until the original network is reduced to a single equivalent component. However, for certain network configurations, this cannot be done simply by combining the components into series- or parallel-connections. Based on Fig. 5.3, it is difficult to combine network components in a “triangle-configuration” into series/parallel connections. Furthermore (and this applies to both methods), sequential substitution and combining of a number of components into the single equivalent component might cause that certain attributes and characteristics of the original components are lost (or “absorbed”) and, therefore, their effects on reliability performance would become more difficult to be identified as the amount of the network reduction is increasing. The example in Fig. 5.4 shows that after applying the network reduction technique (bottom network), it is difficult to estimate the number of actually disconnected customers if a fault occurs on S2, or on L2.

On the other hand, the FMEA method eliminates the need for the transformations of parallel or series connections and directly indicates the predominant failure modes of the system, which then allows for the direct identification of the types of the components that cause specific faults/interruptions. Furthermore, in the FMEA method, the characteristics of each component are still preserved, which makes this method flexible and suitable, or at least possible to use, for the analysis of the control of the network operation. As the FMEA method has been successfully used in a number of previous studies to calculate the reliability indices [25, 140, 144, 145], this thesis also uses the FMEA method for the analysis and establishing the equivalent fault rates and repair times for the modelled/equivalented LV network.

An example of a simple distribution network is shown in Fig 5.5, in order to illustrate abovementioned points. The network in Fig. 5.5 is supplied from a three-phase upstream network (protected with circuit breaker or fuse S) and has three parallel single-phase LV main feeders, with four main sections, each with four lateral spurs/branches supplying a single load point (LP). The symbols SkA and SkB represent the two protection devices (circuit breaker or fuse) installed on each main feeder (*k* is phase: R-red, Y-yellow or B-Blue), Mki represent the corresponding sections on the main feeder, *i*=1, 2, 3, 4, Ski represents protection devices on the lateral spurs (fuse) (*i*=1, 2, 3, 4 spurs), while LPki represents the load points (*i*=1, 2, 3, 4 load points).

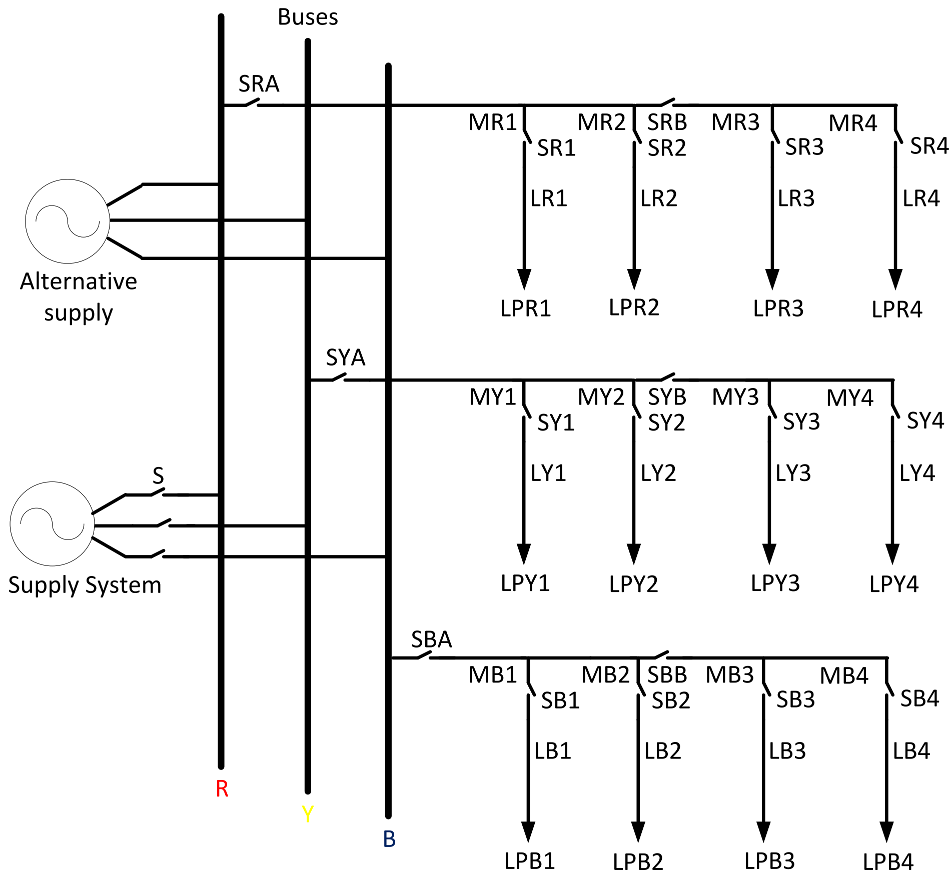


Figure 5.5: Example of simple distribution network

The equations for the calculations of equivalent fault rates, as well as unavailability and repair times for each load point and for the whole network are presented below. Equivalent fault rates at each single-phase load point *k* can be calculated separately for i=1,2 and i=3,4 (due to the second protection device on the main feeder, SkB):

$$\lambda_{LPk1,2} = \sum_{i=1}^{2}(Z\lambda_S + \lambda_{SkA} + \lambda_{Mk1} + \lambda_{Mk2} + \lambda_{Ski} + \lambda_{Lki}) \tag{5.5}$$

$$\lambda_{LPk3,4} = \sum_{i=3}^{4} \begin{matrix}(Z\lambda_S + \lambda_{SkA} + \lambda_{Mk1} + \lambda_{Mk2} + \lambda_{SkB} \\ + \lambda_{Mk3} + \lambda_{Mk4} + \lambda_{Ski} + \lambda_{Lki})\end{matrix} \tag{5.6}$$

where λ_S, λ_{SkA}, λ_{SkB} and λ_{Ski} are fault rates of fuses, λ_{Mk1}, λ_{Mk2}, λ_{Mk3}, λ_{Mk4} and λ_{Lk1} are fault rates of feeders.

The total equivalent fault rate (for the whole LV network) is then:

$$\lambda = \frac{\sum_{k=1}^{3}(\lambda_{LPk1}+\lambda_{LPk2}+\lambda_{LPk3}+\lambda_{LPk4})}{N} \tag{5.7}$$

where N is the number of customer load points.

Similarly, equivalent unavailabilities are calculated as:

$$U_{LPk1,2} = \sum_{i=1}^{2} \begin{matrix}(Z\lambda_S r_S + \lambda_{SkA} r_{SkA} + \lambda_{Mk1} r_{Mk1} \\ +\lambda_{Mk2} r_{Mk2} + \lambda_{Ski} r_{Ski} + \lambda_{Lki} r_{Lki})\end{matrix} \tag{5.8}$$

$$U_{LPk3,4} = \sum_{i=3}^{4} \begin{matrix}(Z\lambda_S r_S + \lambda_{SkA} r_{SkA} + \lambda_{Mk1} r_{Mk1} + \lambda_{Mk2} r_{Mk2} + \lambda_{SkB} r_{SkB} \\ +\lambda_{Mk3} r_{Mk3} + \lambda_{Mk4} r_{Mk4} + \lambda_{Ski} r_{Ski} + \lambda_{Lki} r_{Lki})\end{matrix} \tag{5.9}$$

where r_S, r_{SkA}, r_{SkB} and r_{Ski} are repair times of fuses, r_{Mk1}, r_{Mk2}, r_{Mk3}, r_{Mk4} and r_{Lk1} are repair times of feeders.

The total equivalent unavailability (for the whole LV network) is:

$$U = \frac{\sum_{k=1}^{3} U_{LPk1}+U_{LPk2}+U_{LPk3}+U_{LPk4}}{N} \tag{5.10}$$

If fuse-saving protection is applied, the protection devices SkA and SkB are circuit breakers and the equations are different from the previous ones.

Equivalent fault rates at each single-phase load point *k*:

$$\lambda_{LPk1,2} = Z\lambda_S + \lambda_{SkA} + \lambda_{Mk1} + \lambda_{Mk2} + \sum_{i=1}^{2}(\lambda_{Ski} + \lambda_{Lki}) \tag{5.11}$$

$$\lambda_{LPk3,4} = Z\lambda_S + \lambda_{SkA} + \lambda_{Mk1} + \lambda_{Mk2} + \lambda_{SkB} + \lambda_{Mk3} + \lambda_{Mk4} + \sum_{i=3}^{4}(\lambda_{Ski} + \lambda_{Lki}) \tag{5.12}$$

The total equivalent fault rate:

$$\lambda = \frac{\sum_{k=1}^{3} \lambda_{LPk1}+\lambda_{LPk2}+\lambda_{LPk3}+\lambda_{LPk4}}{N} \tag{5.13}$$

Equivalent unavailabilities:

$$U_{LPk1,2} = Z\lambda_S r_S + \lambda_{SkA} r_{SkA} + \lambda_{Mk1} r_{Mk1} + \lambda_{Mk2} r_{Mk2} + \sum_{i=1}^{2}(\lambda_{Ski} r_{Ski} + \lambda_{Lki} r_{Lki}) \tag{5.14}$$

$$U_{LPk3,4} = Z\lambda_S r_S + \lambda_{SkA} r_{SkA} + \lambda_{Mk1} r_{Mk1} + \lambda_{Mk2} r_{Mk2} + \lambda_{SkB} r_{SkB} + \lambda_{Mk3} r_{Mk3} + \lambda_{Mk4} r_{Mk4} + \sum_{i=3}^{4} (\lambda_{Ski} r_{Ski} + \lambda_{Lki} r_{Lki}) \quad (5.15)$$

The total equivalent unavailability:

$$U = \frac{\sum_{k=1}^{3} U_{LPk1} + U_{LPk2} + U_{LPk3} + U_{LPk4}}{N} \quad (5.16)$$

This gives the total equivalent repair time:

$$r = \frac{U}{\lambda} \quad (5.17)$$

Again, in above equations k is red, yellow or blue phase and N is the number of customer load points. If there is an always available unconstrained alternative supply point, $Z\lambda_S$ is equal to 0.

It should be noted that the above equations are different from those in [5], in which the equivalent fault rate for the whole LV network is a simple sum of fault rates of all components, while the equivalent repair time for the whole LV network is the average value of repair times of all components, as given in (5.18) and (5.19).

$$\lambda_{eq} = \sum_{i=1}^{N} \lambda_i \quad (5.18)$$

$$r_{eq} = \frac{1}{N} \sum_{i=1}^{N} r_i \quad (5.19)$$

Generally, equations (5.18) and (5.19) can be applied when there are no protection devices within the modelled network, which is not the case in the real networks [88], [89], as LV networks are always protected by either fuses or circuit breakers.

5.2.3 Formulation and Analysis of Reliability Equivalents of Generic Residential LV Networks

DNOs are required to report annually on both their target and achieved reliability performance to the Regulator (OFGEM in the UK) and to the general public. In order to satisfy the imposed targets and to plan their investments in network reliability, DNOs use various network modelling approaches, which however may not be completely adequate. For example, and as discussed previously, there will be much higher levels of uncertainties and, therefore, bigger errors in the estimated or calculated reliability indices if the input data (fault rates and repair times) are not properly disaggregated based on the actual types of the components, specific area supplied by different networks, etc. This has been confirmed in the numerous reliability performance studies [128, 138, 139], where LV and MV networks (i.e. 33 kV, 11 kV, and 0.4 kV networks in the UK) have been simply represented by the aggregate/bulk load, in which the characteristics, parameters and data required for a more detailed reliability assessment were neglected in the analysis.

This thesis aims to contribute to resolving the above issues by formulating more accurate equivalent reliability models of the four previously developed generic LV/MV networks, ultimately resulting in a more confident reliability performance assessment. This is presented in the further text, where specific numbers of customers for the load points from the four generic network models from Chapter 4 are now given for calculating reliability equivalents of the corresponding networks of different sizes (supplying estimated different numbers of customers).

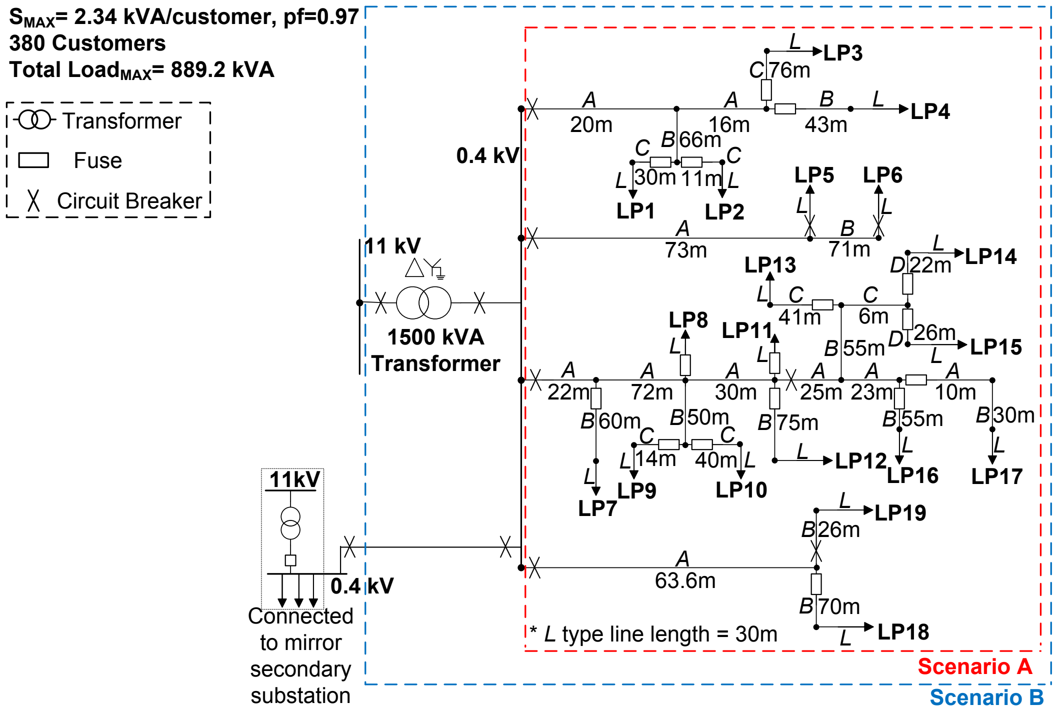


Figure 5.6: Generic residential LV highly-urban (HU) distribution network [77, 102, 103, 104, 105].

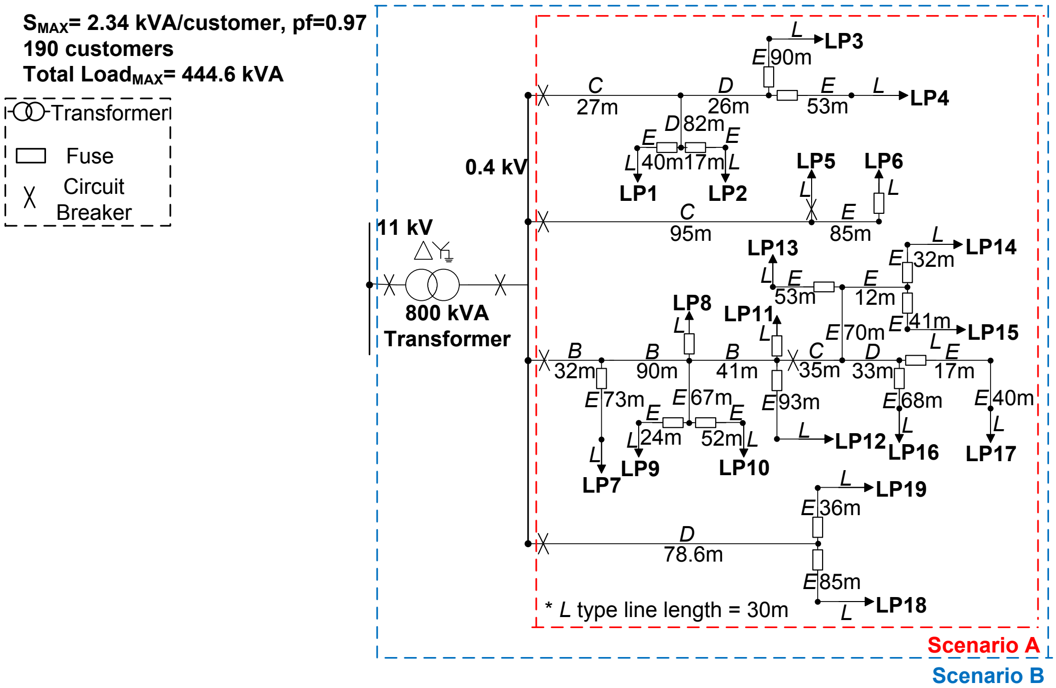


Figure 5.7: Generic residential LV urban (U) distribution network [39, 77, 102, 103, 104].

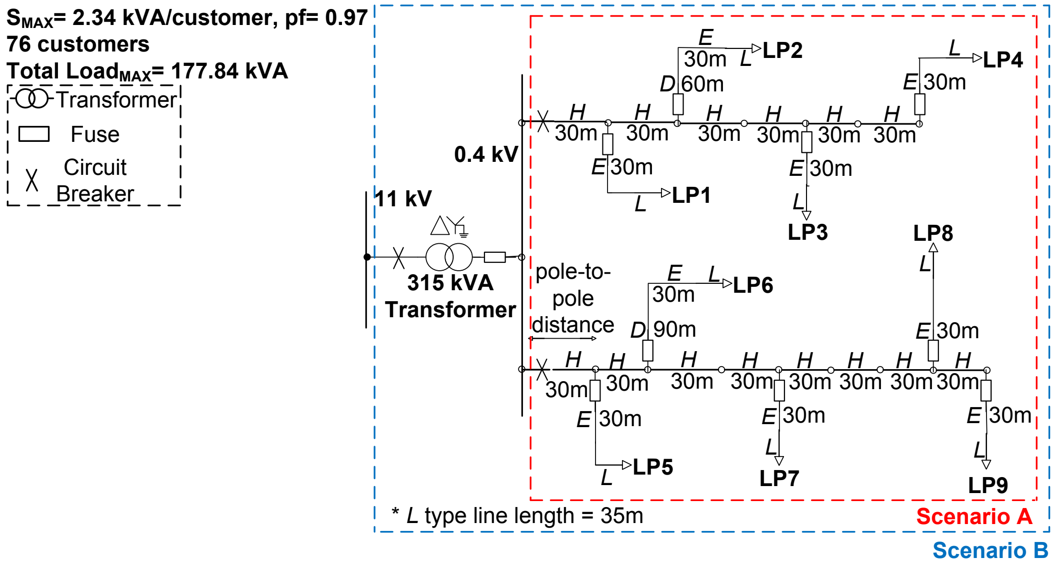


Figure 5.8: Generic residential LV sub-urban (SU) distribution network [77, 97, 101, 103, 104, 106].

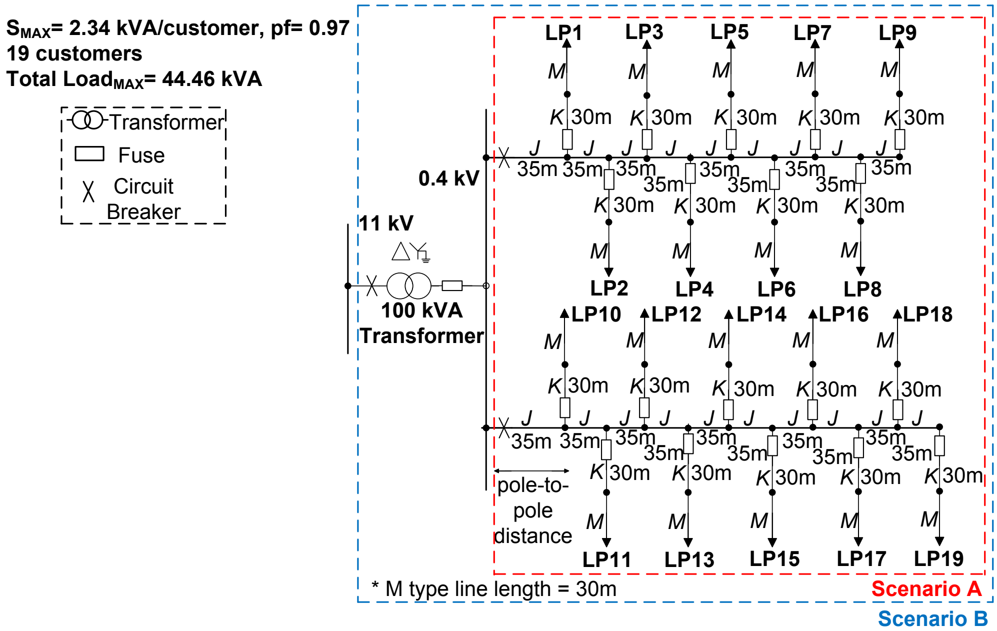


Figure 5.9: Generic residential LV rural (R) distribution network [77, 103, 104, 106].

Table 5.6: Estimated number of supplied customers (based on transformer rating).

Sub-sector	HU (TX1)			U (TX2)			SU (TX3)			R (TX4)		
Transformer size (kVA)	1500	1000	800	800	500	315	315	200	100	100	50	25
	Size of customers											
LP1	21	15	12	8	5	3	6	3	3	1	1	0
LP2	21	15	12	8	5	3	11	6	3	1	1	0
LP3	16	10	9	6	3	3	13	7	2	1	1	0
LP4	20	14	11	4	3	3	4	3	0	1	1	0
LP5	33	21	18	30	18	12	5	3	3	1	1	0
LP6	33	21	18	15	9	6	16	10	3	1	1	0
LP7	20	14	9	11	6	3	10	6	4	1	1	0
LP8	20	14	9	12	6	3	3	3	1	1	1	0
LP9	24	15	9	9	6	3	8	5	0	1	1	0
LP10	14	9	6	8	5	3	-	-	-	1	0	0
LP11	10	7	6	6	3	3	-	-	-	1	0	0
LP12	22	15	9	12	6	4	-	-	-	1	0	0
LP13	16	10	9	9	6	3	-	-	-	1	0	0
LP14	8	5	5	6	3	3	-	-	-	1	0	0
LP15	8	5	5	6	3	3	-	-	-	1	0	0
LP16	22	12	6	9	6	3	-	-	-	1	0	1
LP17	14	9	6	7	5	3	-	-	-	1	0	1
LP18	31	21	16	12	6	6	-	-	-	1	0	1
LP19	27	18	15	12	6	6	-	-	-	1	0	1
Total	380	250	190	190	110	76	76	46	19	19	9	4

5.2.4 Calculated Results for Reliability Equivalents of Generic Residential LV Networks

In order to verify the calculated results, both analytical calculations and probabilistic simulations were used to quantify the reliability performance of the modelled generic LV networks. As discussed before, analytical approaches calculate the same set of output results (mean values) for the same set of input data, parameters and models, while probabilistic simulations offer a comprehensive evaluation of the reliability performance, as the output results are expressed as the probability distributions (showing ranges of variations), rather than one set of output data (e.g. mean values). As previously discussed, exponential distribution is applied to the initial conditions of the component fault rates and mean repair times, although Weibull, normal or

Poisson could be adopted as well. Accordingly, the exponential distribution function has been applied for the final selection of the fault rates and repair times for calculating results presented in this chapter, based on [48, 49, 50].

In the presented analysis, two different scenarios are modelled for each network, as indicated in Figs 5.6-5.9. In Scenario A, the reliability equivalent was calculated for the LV network within the rectangle indicated with red dashed line (without secondary distribution substation), while in Scenario B the reliability equivalent was calculated for the LV network within the rectangle indicated with blue dashed line (with secondary distribution substation). Even though in most of the studies (e.g. [142, 143, 146, 147, 148, 149, 150, 151]) the analysis has been performed for the reliability equivalent as presented in Scenario B, this does not exclude studies in which the equivalent model is applied only for the load/demand connected at the secondary distribution substation.

Fig. 5.6 shows that the HU LV network is supported from an adjacent 11/04kV secondary substation, through a cable connection between the two identical LV substations [105], where each substation was equipped with a single busbar only. Based on Table 5.6, the sub-sectors were segregated into different transformer sizes, and it was possible that different sub-sectors overlap, as each of them has three different possible transformer sizes. As a result, every feeder size for each sub-sector from Table 4.4 in Chapter 4 is matched with the corresponding transformer size (for each sub-sector) from Table 4.5 (also in Chapter 4). As the network configurations and transformer sizes depend on the number of supplied customers, changing the transformer size corresponds to different numbers of supplied customers for every sub-sector, which is further disaggregated for each load point (LP) in Table 5.6, showing the number of supplied customers for different generic networks with various sizes of transformers.

5.2.5 Mean Values

Tables 5.7 and 5.8 compare results calculated by both analytical and probabilistic approaches (mean values only).

Table 5.7: Comparison of analytical and probabilistic results (mean values) for Scenario A.

Sub-sector	Transformer size (kVA)	Analytical			Probabilistic		
		λ_{eq_j}		μ_{eq_j}	λ_{eq_j}		μ_{eq_j}
		LI	SI		LI	SI	
HU	1500	0.0194	0.0210	9.4023	0.0192	0.0206	9.3585
	1000	0.0161	0.0174	9.8371	0.0159	0.0171	9.7555
	800	0.0146	0.0158	10.1107	0.0145	0.0155	10.0188
U	800	0.0175	0.0223	8.3464	0.0177	0.0223	8.3382
	500	0.0155	0.0197	8.7478	0.0156	0.0197	8.7387
	315	0.0141	0.0179	8.8240	0.0142	0.0180	8.8159
SU	315	0.0224	0.0499	9.4684	0.0221	0.0495	9.5321
	200	0.0197	0.0438	9.7067	0.0194	0.0436	9.7744
	100	0.0145	0.0323	11.0323	0.0144	0.0322	11.1503
R	100	0.0208	0.0657	11.8988	0.0208	0.0651	11.6976
	50	0.0192	0.0608	12.2280	0.0192	0.0605	12.0387
	25	0.0237	0.0750	11.4001	0.0234	0.0736	11.2416

Table 5.8 Comparison of analytical and probabilistic results (mean values) for Scenario B.

Sub-sector	Transformer size (kVA)	Analytical			Probabilistic		
		λ_{eq_j}		μ_{eq_j}	λ_{eq_j}		μ_{eq_j}
		LI	SI		LI	SI	
HU	1500	0.0207	0.0224	9.0569	0.0208	0.0222	9.0676
	1000	0.0174	0.0189	9.3932	0.0175	0.0187	9.3936
	800	0.0159	0.0173	9.6022	0.0160	0.0171	9.6008
U	800	0.0254	0.0323	14.4538	0.0254	0.0323	14.7206
	500	0.0233	0.0297	15.2650	0.0233	0.0297	15.5551
	315	0.0219	0.0279	15.7208	0.0219	0.0280	16.0288
SU	315	0.0312	0.0694	15.3769	0.0311	0.0694	15.3245
	200	0.0284	0.0633	16.1080	0.0284	0.0634	16.0507
	100	0.0233	0.0462	18.3536	0.0234	0.0518	18.1948
R	100	0.0309	0.0978	18.8734	0.0314	0.0986	18.6304
	50	0.0293	0.0929	19.4602	0.0298	0.0939	19.3086
	25	0.0338	0.01071	17.9224	0.0349	0.1086	17.6007

Table 5.9 Analytical results based on conventional equivalent equation (5.18 & 5.19) for Scenario A.

Sub-sector	Transformer size (kVA)	Analytical		
		λ_{eq_j}		μ_{eq_j}
		LI	SI	
HU	1500	0.9952	1.0782	7.4779
	1000	0.7740	0.8384	7.6602
	800	0.6719	0.7278	7.7898
U	800	0.6529	0.8310	7.2273
	500	0.5281	0.6721	7.3235
	315	0.4751	0.6046	7.3840
SU	315	0.2313	0.5148	5.9467
	200	0.1984	0.4416	5.7410
	100	0.1595	0.3549	5.8539
R	100	0.1313	0.4158	4.8768
	50	0.0606	0.1919	4.8692
	25	0.0270	0.0856	4.9059

The calculations of results in Table 5.9 is based on (5.18) and (5.19), showing that as the number of supplied customers increase (from R, to SU and U, to HU networks), the number of interruptions and durations of these interruptions increase. This follows (5.18), reflecting increase of network components for increased number of supplied customers, therefor resulting in increasing fault rates and mean repair times. By comparing Tables 5.7 and 5.9, the number of interruptions in Table 5.7 is lower, showing that the network performance for reliability equivalents is more accurately assessed if a simple sum of all components' fault rates is not used.

It can be seen from the results in Tables 5.7 and 5.8 that the equivalent fault rates for each sub-sector have the general tendency to decrease when the number of served customers (i.e. the size of the supplying network/transformer) is reduced, while the trend for the equivalent repair times is the opposite. The only exception is the 25kVA transformer in generic rural LV networks, which is the only single-phase transformer. For example, the higher equivalent fault rates in this case are due to the connection of only four customers to the one single-phase feeder (Table 5.6), while nine customers are supplied by a three-phase 50 kVA transformer (through which each single-phase feeder is supplying three customers), resulting in a lower probability of a fault for the latter case.

The trends in Tables 5.7 and 5.8 are due to the decreasing numbers of network components as the size of the network is reduced to supply the lower number of customers. Consequently, as the number of network components decreases, the contributions of fault rates of individual components to the total/equivalent fault rate of the whole network is smaller, while an increase of the equivalent repair times is strongly impacted by the predominant contributions from L and M types of service connection feeders (from Table 4.4 and Figs. 4.4-4.8 in Chapter 4).

Practically all calculated results for the different types of the networks, supplying residential customers in the four generic sub-sectors, show an overall trend of increasing equivalent fault rate and repair time values from HU, through U and SU, to R networks. In order to verify this “trend”, the results for calculated mean values from Tables 5.7 and 5.8 are compared with available data from Swedish benchmarking report [152] given in Table 5.10, which presents the statistics from 64 different DNOs in Sweden for 11 years (from year 1998 to 2008).

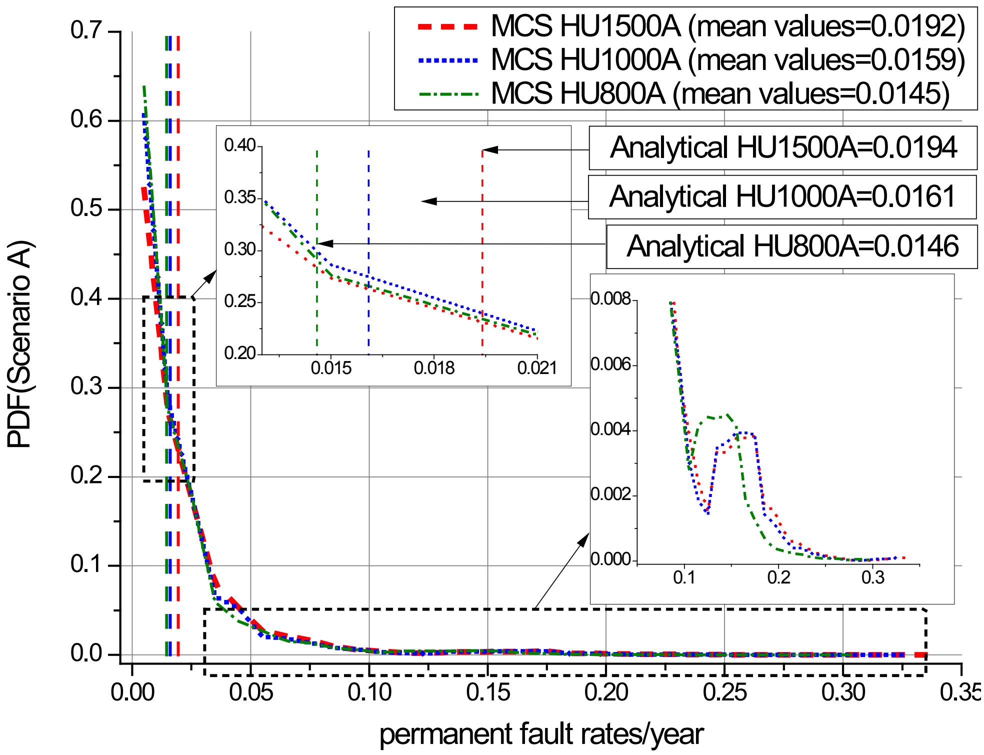
Table 5.10: Swedish Benchmark report [152]

Sub-sectors	SAIFI	SAIDI	CAIDI (hours)
Urban	0.30	0.30	1.00
Sub-urban	0.69	1.20	1.74
Rural	1.65	6.00	3.64

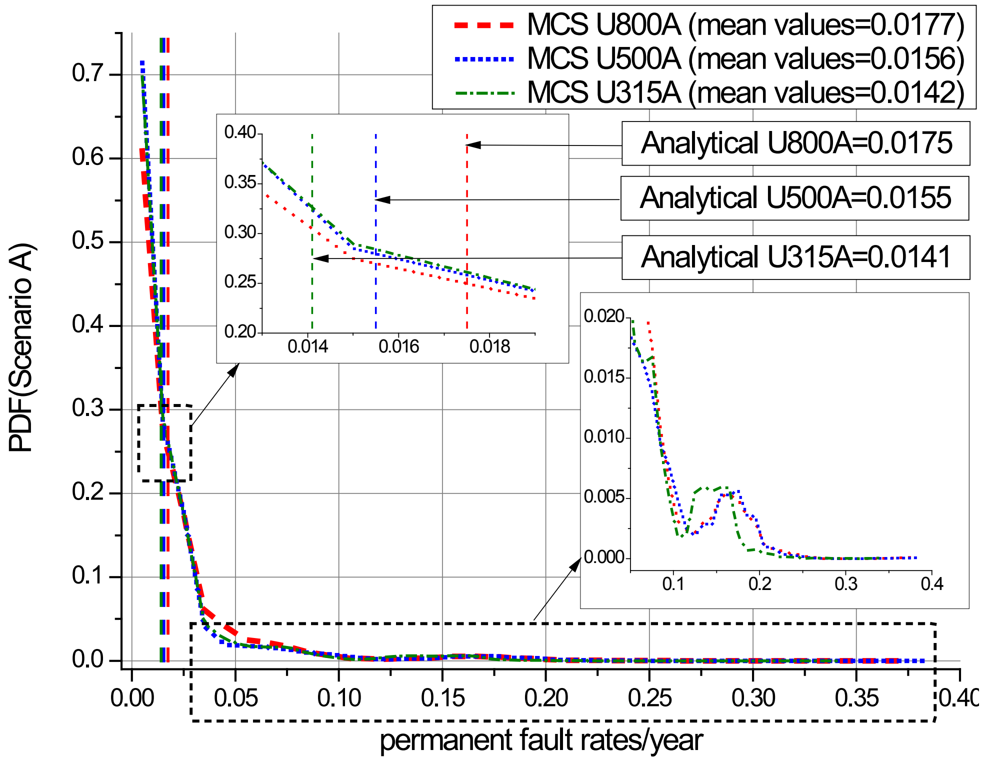
Moreover, in Table 5.7 for scenario A, only HU results are different, featuring higher equivalent fault rates and equivalent repair times than the U sector results due to higher number of network components. As for Table 5.8, the HU sector had lower equivalent failure rates and equivalent repair times than the U sector, in this case due to the presence of alternative supply (from adjacent LV network). Therefore, in order to verify the results, they should be calculated as a whole network (Scenario B), and not part of the network (Scenario A). In that way, the presented results demonstrate a pattern of improving reliability performance from rural and sub-urban networks, to urban and highly-urban networks, generally confirming the validity of the presented methodology and obtained results. Additionally, it is very to verify the presented results by comparison with the Swedish Benchmark Report [152] and recorded statistics in Table 5.10, as these results are related to both LV and MV networks.

5.2.6 Probability Distributions

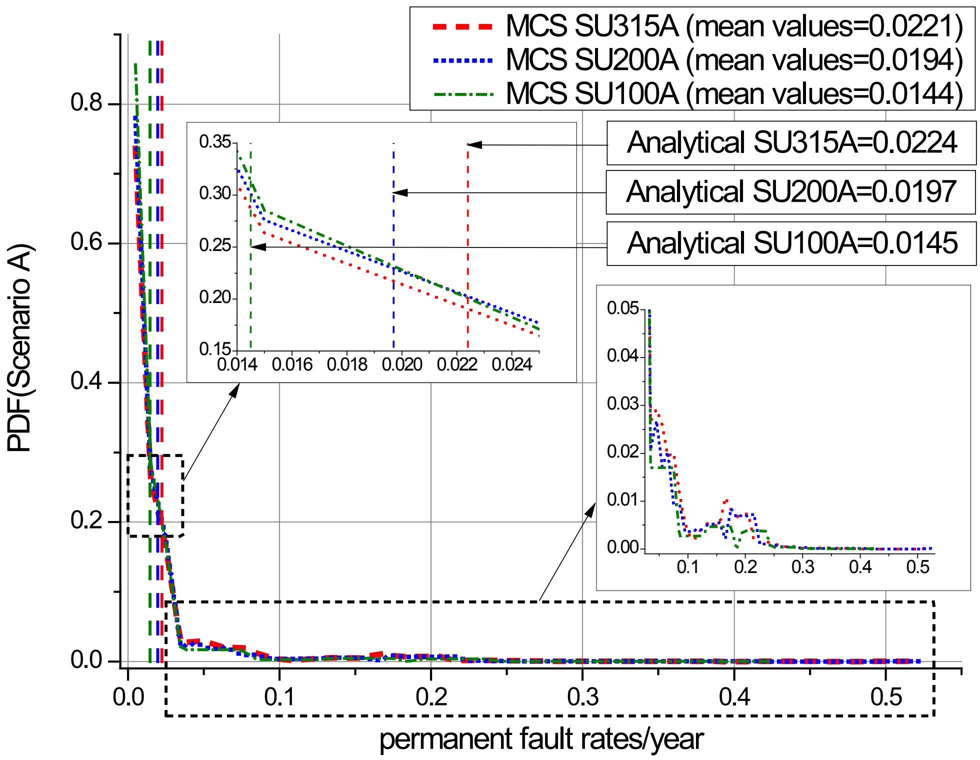
In addition to Tables 5.7 and 5.8, the results from the probabilistic approach (Monte Carlo Simulations, MCS) provide information on both mean values and distributions of the calculated equivalent fault rates and mean repair time. These results are illustrated in Figs. 5.10-5.15, where the calculated equivalent fault rates for different sizes of the four generic LV networks from Table 5.6 are divided in "permanent" and "temporary/transient" faults, corresponding to LIs and SIs. Distributions of equivalent mean repair times are given for permanent faults, which typically result in LIs. The results are provided first for Scenario A (Figs. 5.10-5.12) and then for Scenario B (Figs. 5.13-5.15).



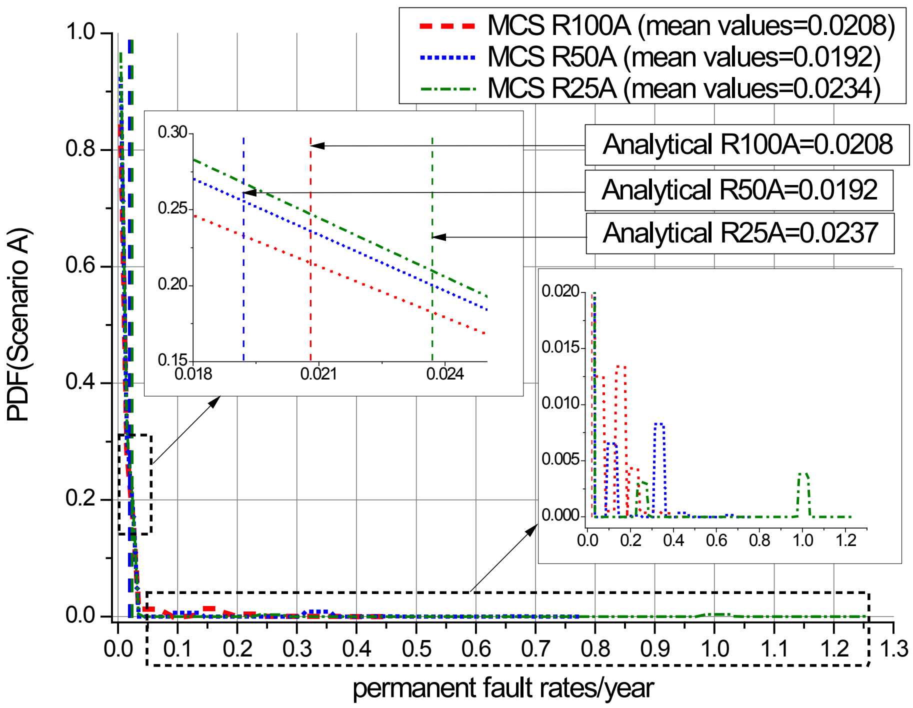
(a) highly-urban (HU)



(b) urban (U)

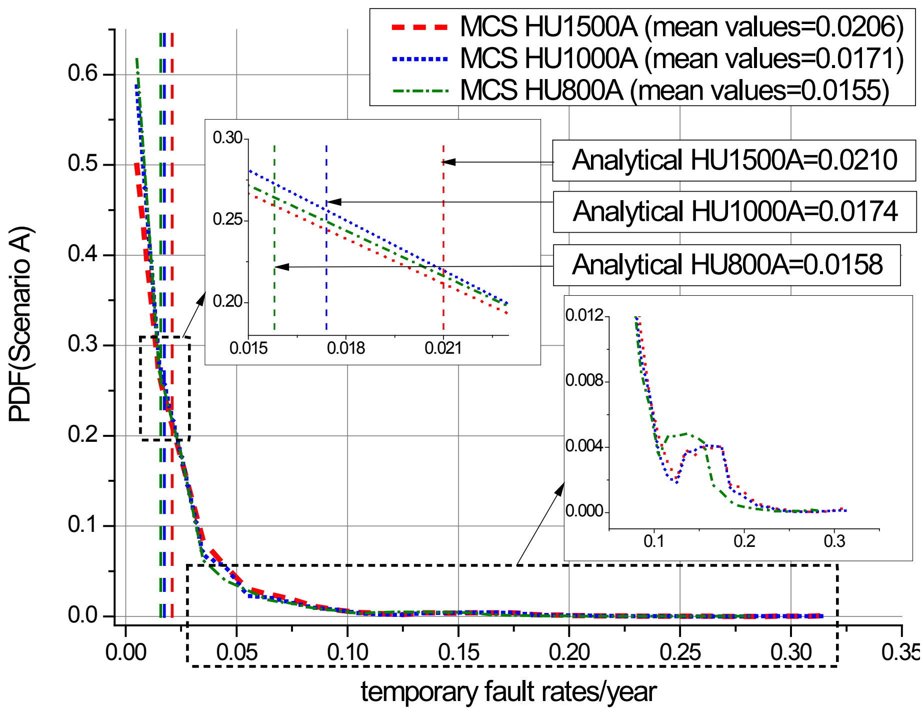


(c) sub-urban (SU)

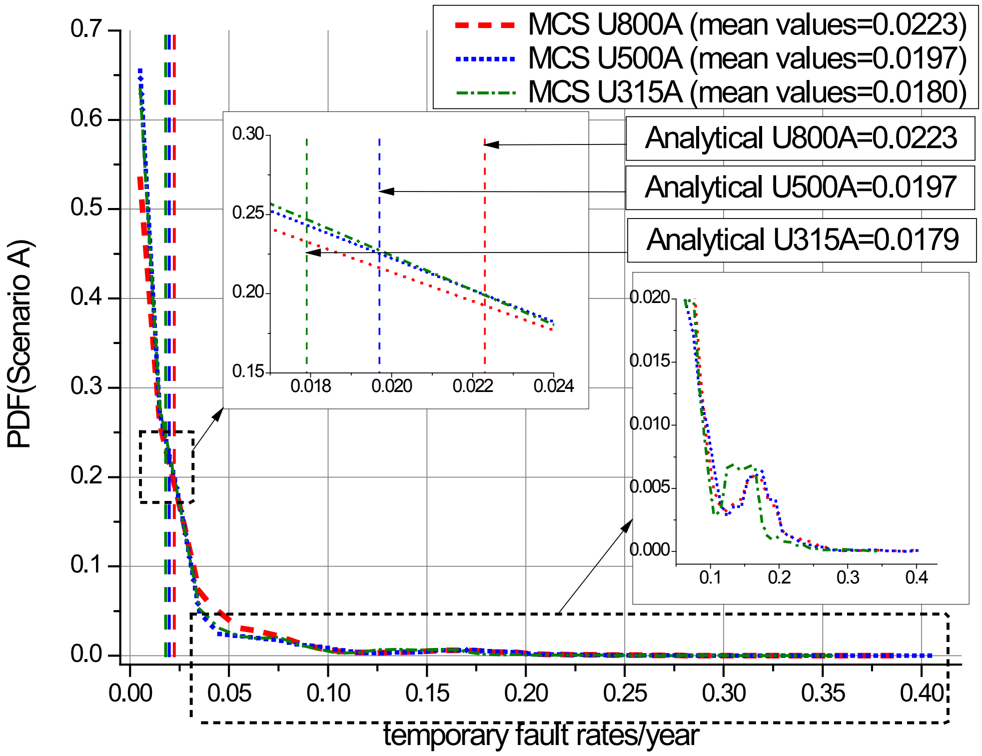


(d) rural (R)

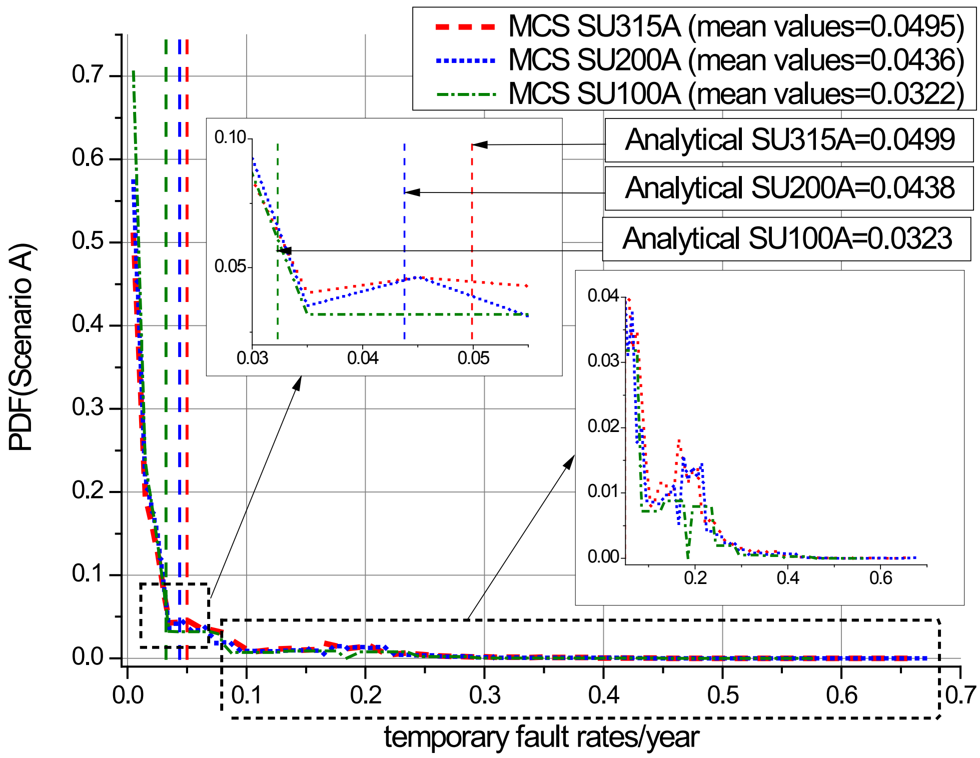
Figure 5.10: Equivalent fault rates (permanent faults resulting in LIs) for Scenario A and different sizes of network/transformers from Table 5.6 (indicated in Legend).



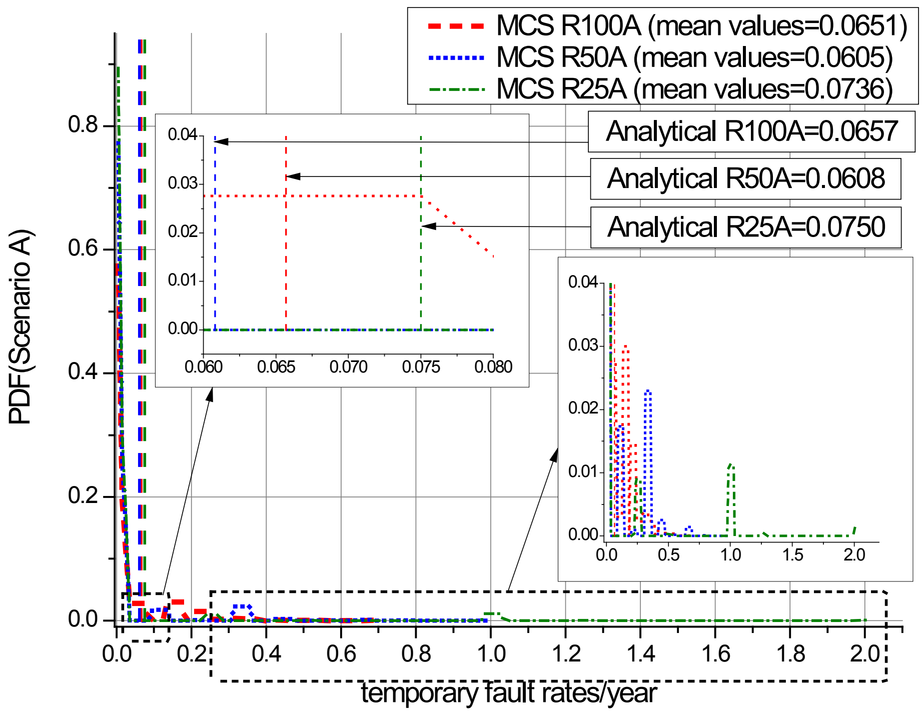
(a) highly-urban (HU)



(b) urban (U)

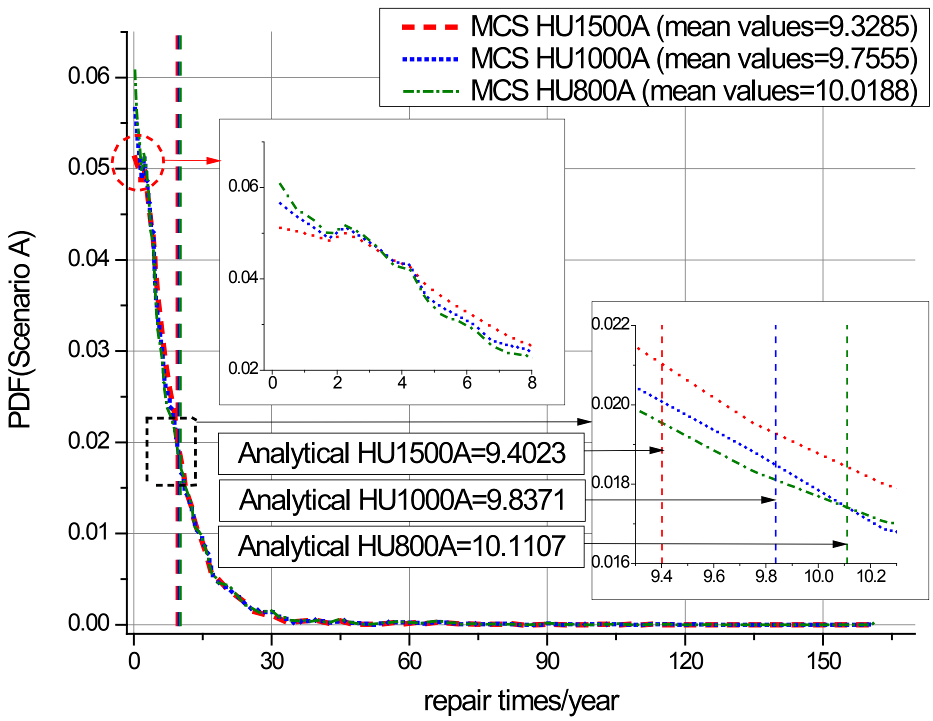


(c) sub-urban (SU)

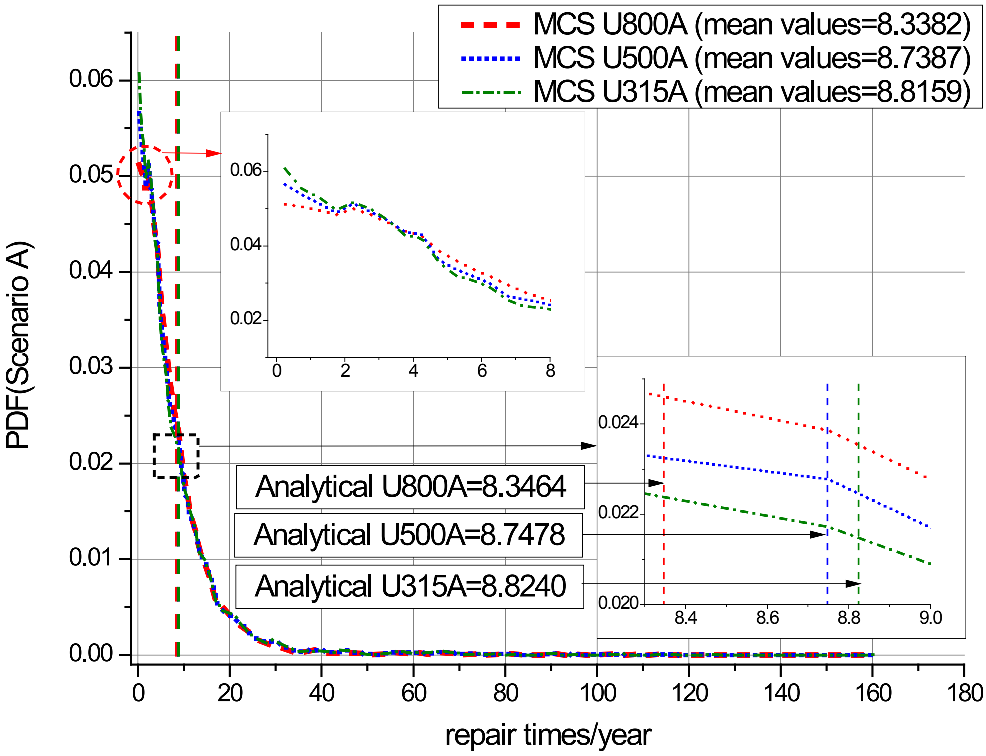


(d) rural (R)

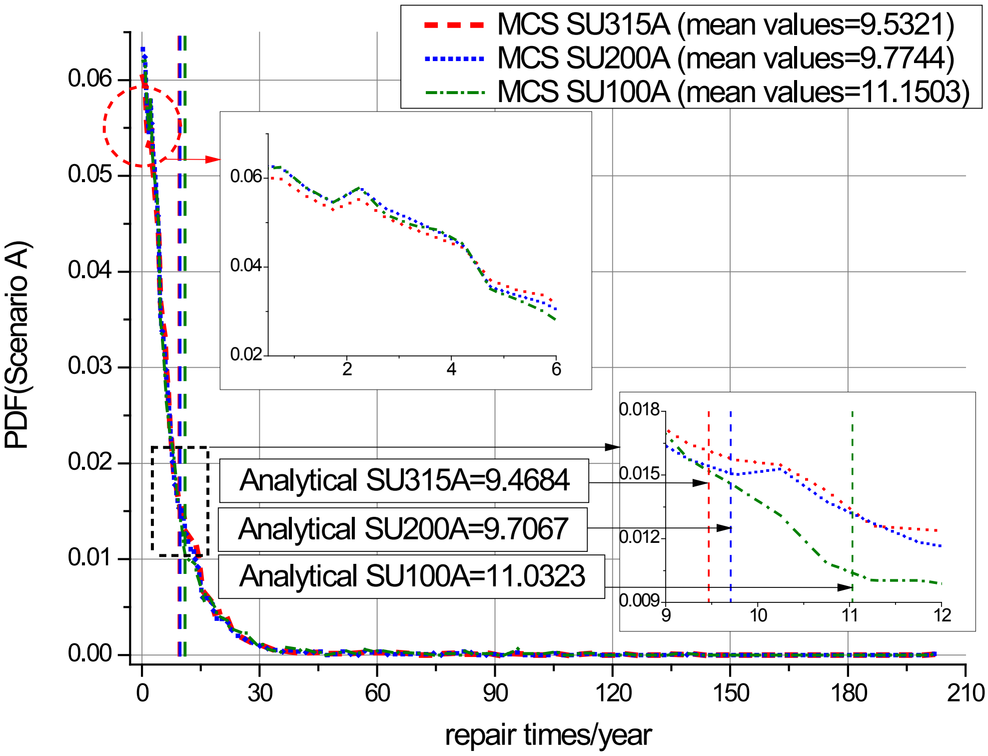
Figure 5.11: Equivalent fault rates (temporary faults resulting in SIs) for Scenario A and different sizes of network/transformers from Table 5.6 (indicated in Legend).



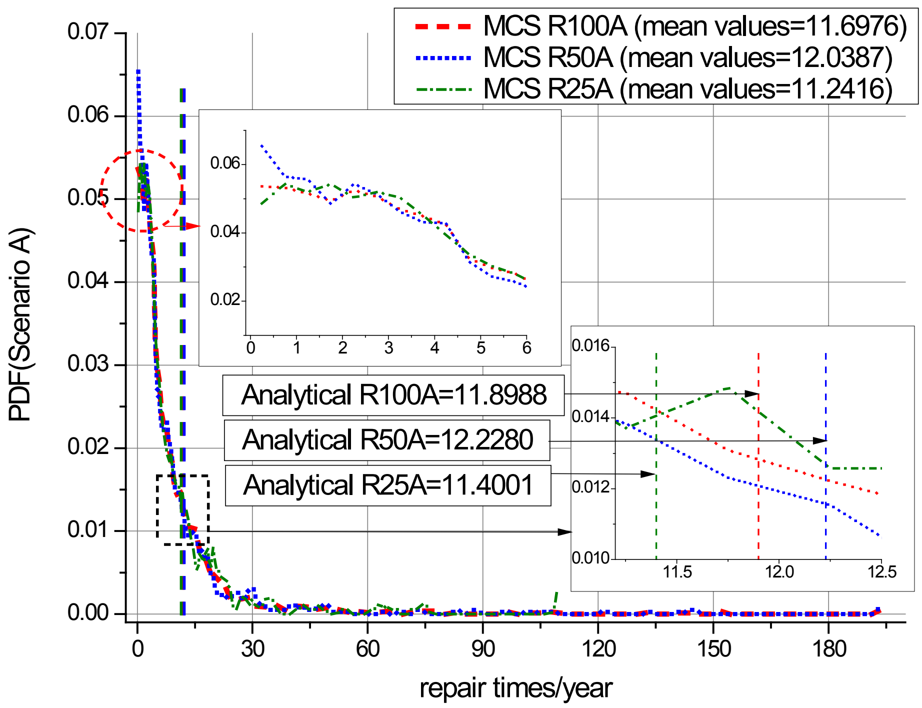
(a) highly-urban (HU)



(b) urban (U)

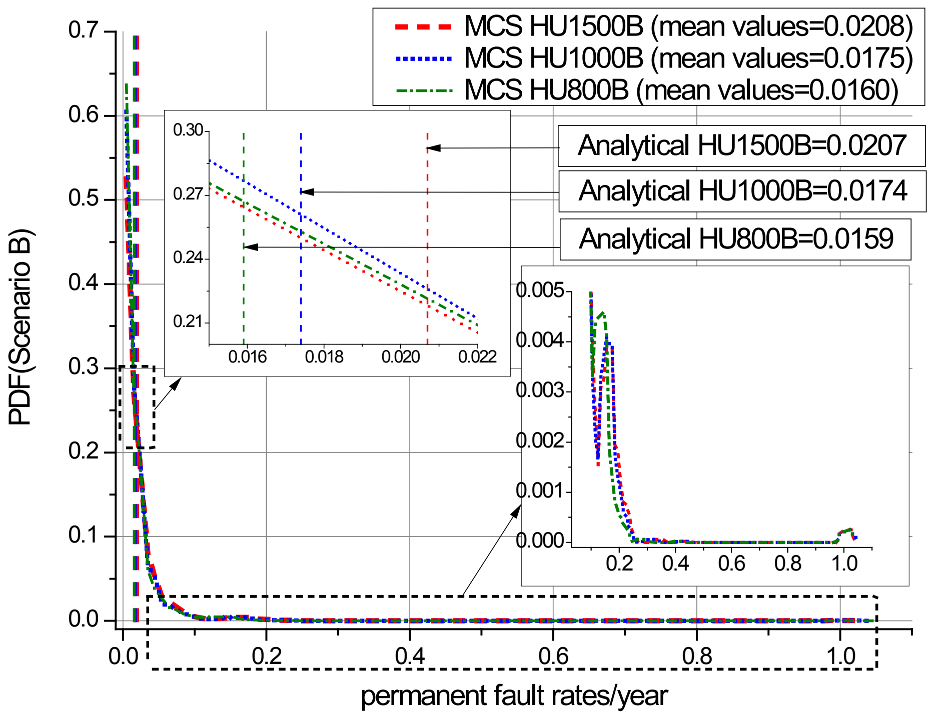


(c) sub-urban (SU)

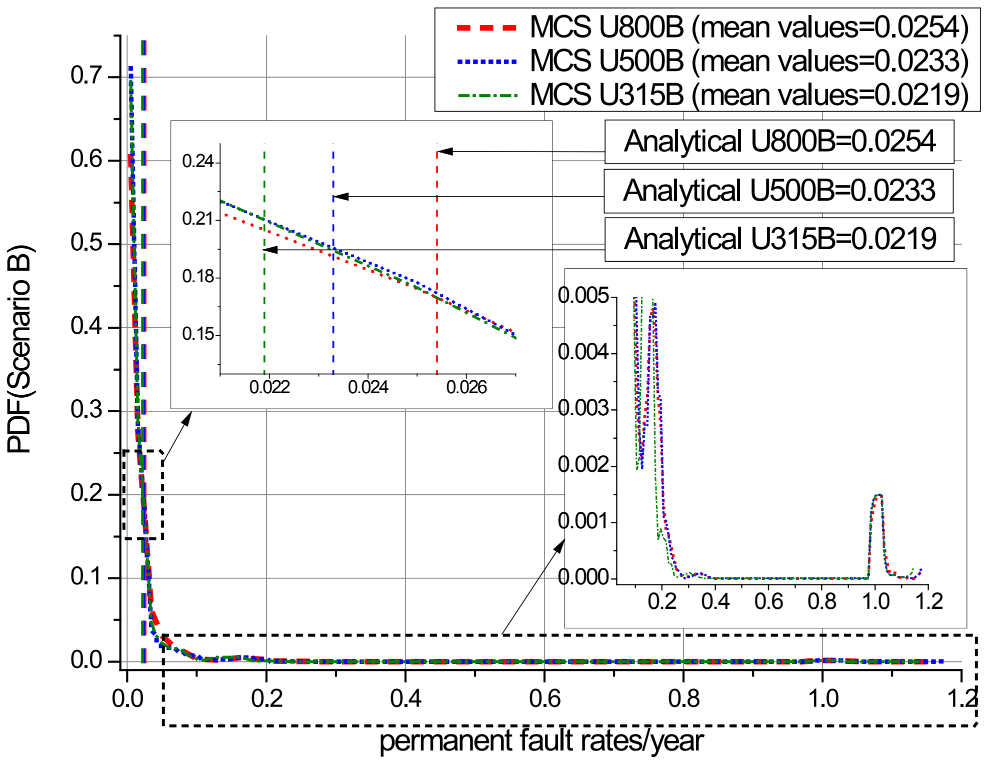


(d) rural (R)

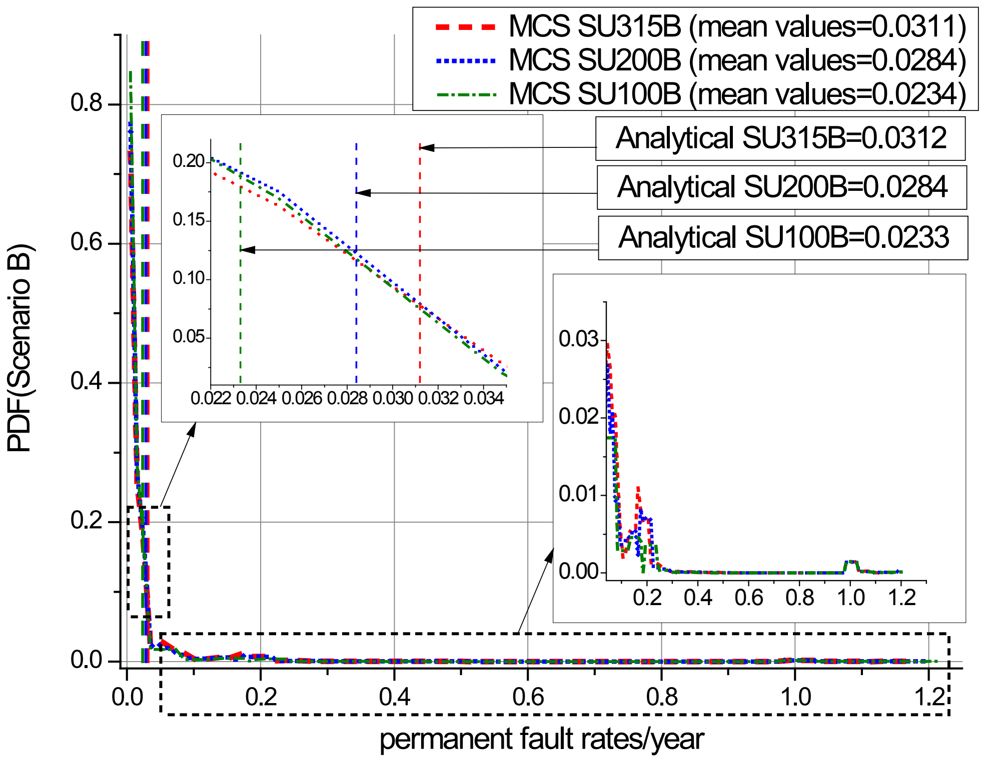
Figure 5.12: Equivalent repair times (after LIs) for Scenario A and different sizes of network/transformers from Table 5.6 (indicated in Legend).



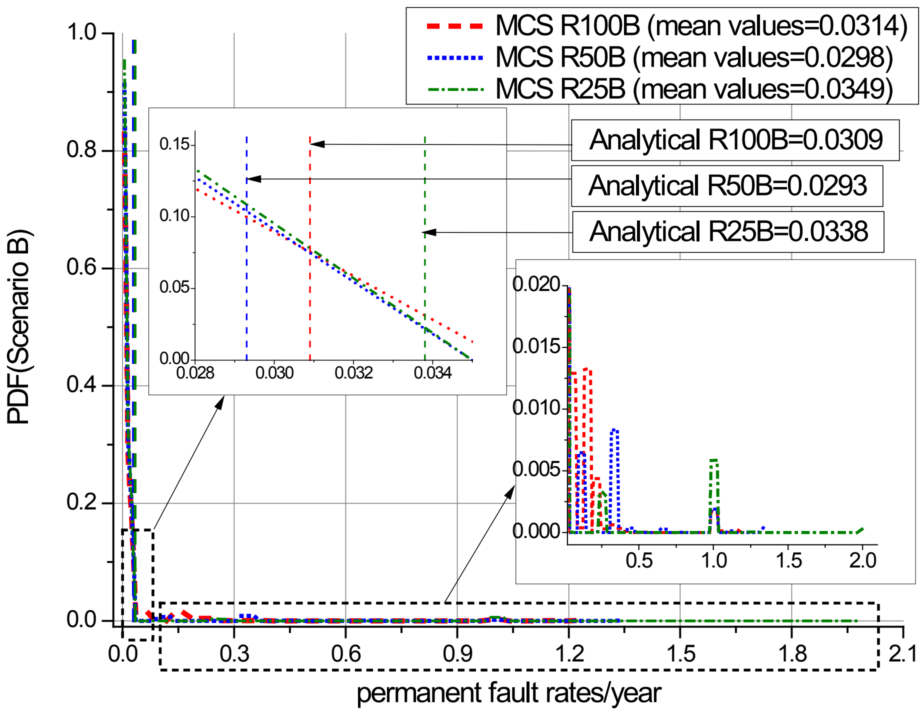
(a) highly-urban (HU)



(b) urban (U)

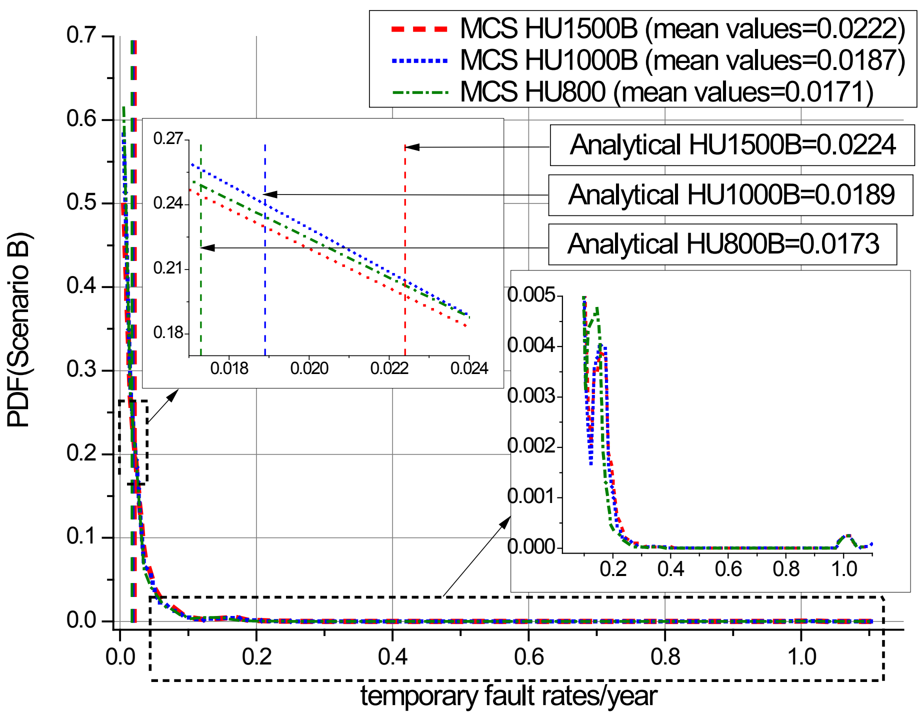


(c) sub-urban (SU)

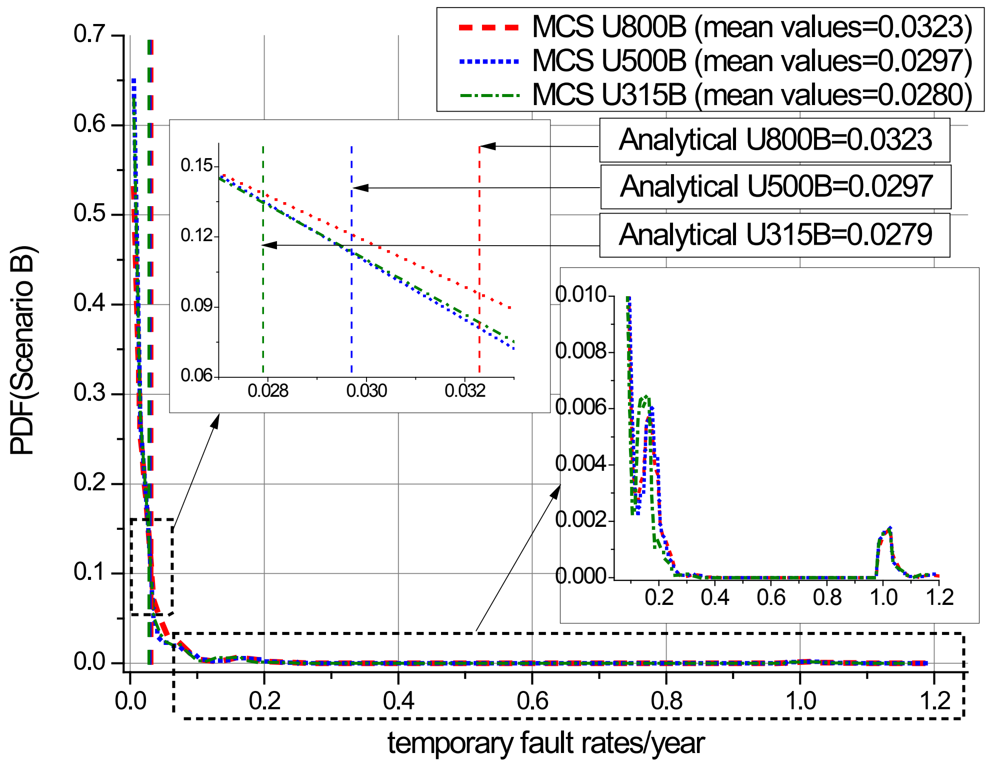


(d) rural (R)

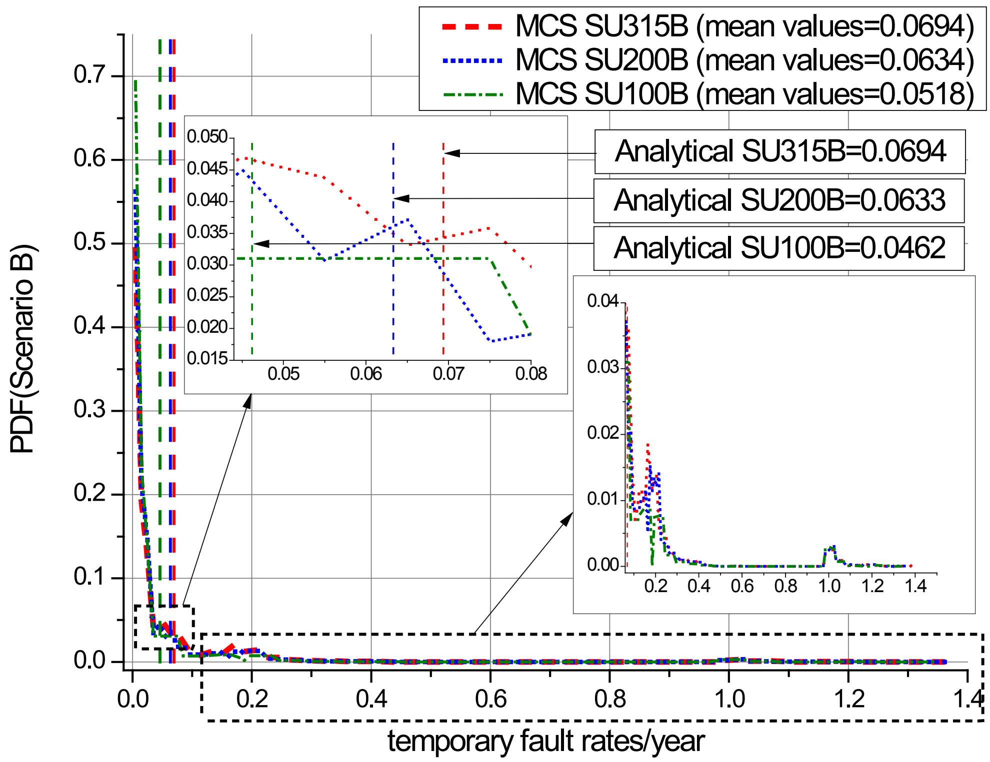
Figure 5.13: Equivalent fault rates (permanent faults resulting in LIs) for Scenario B and different sizes of network/transformers from Table 5.6 (indicated in Legend).



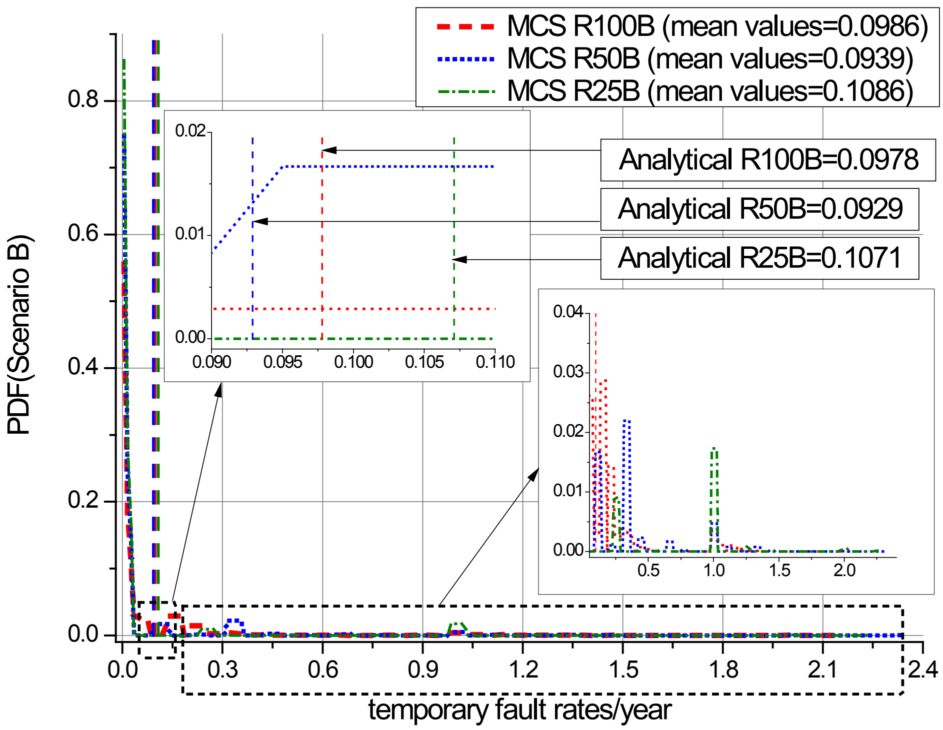
(a) highly-urban (HU)



(b) urban (U)

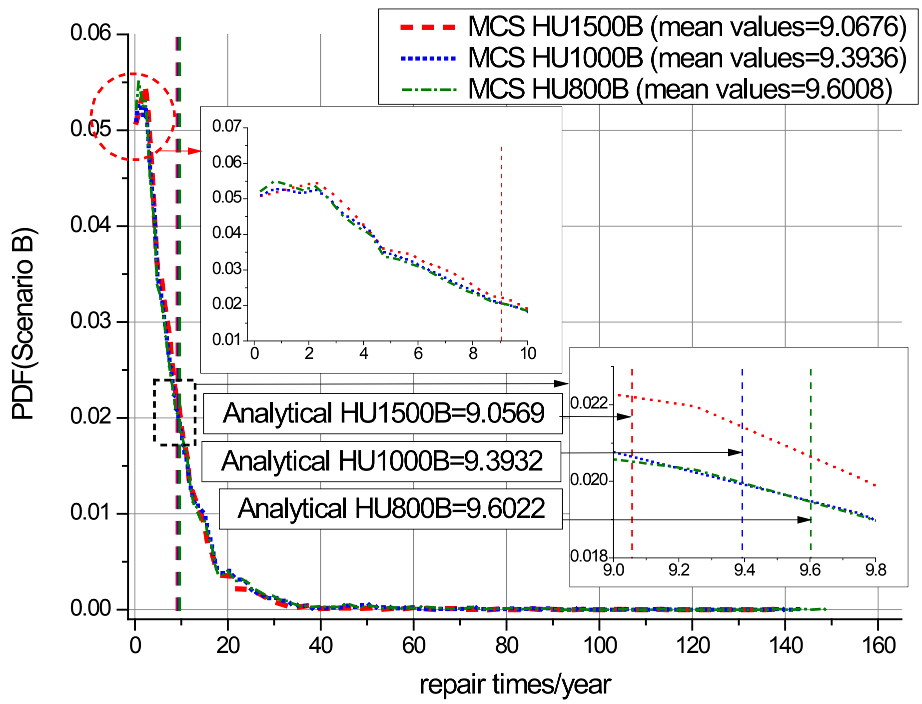


(c) sub-urban (SU)

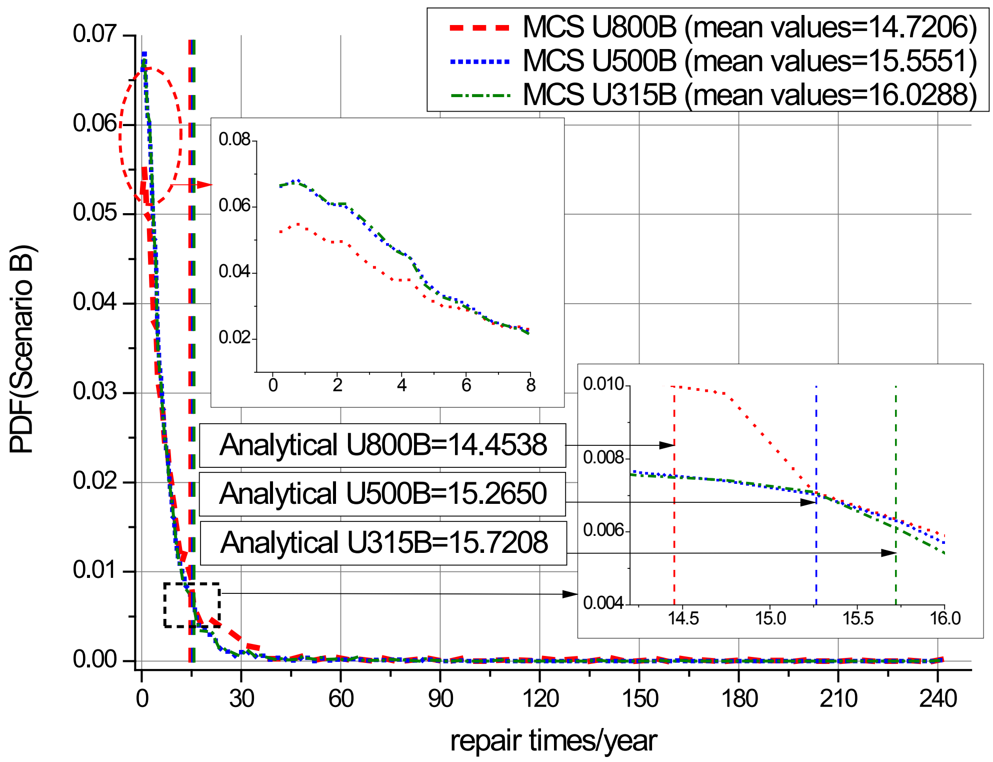


(d) rural (R)

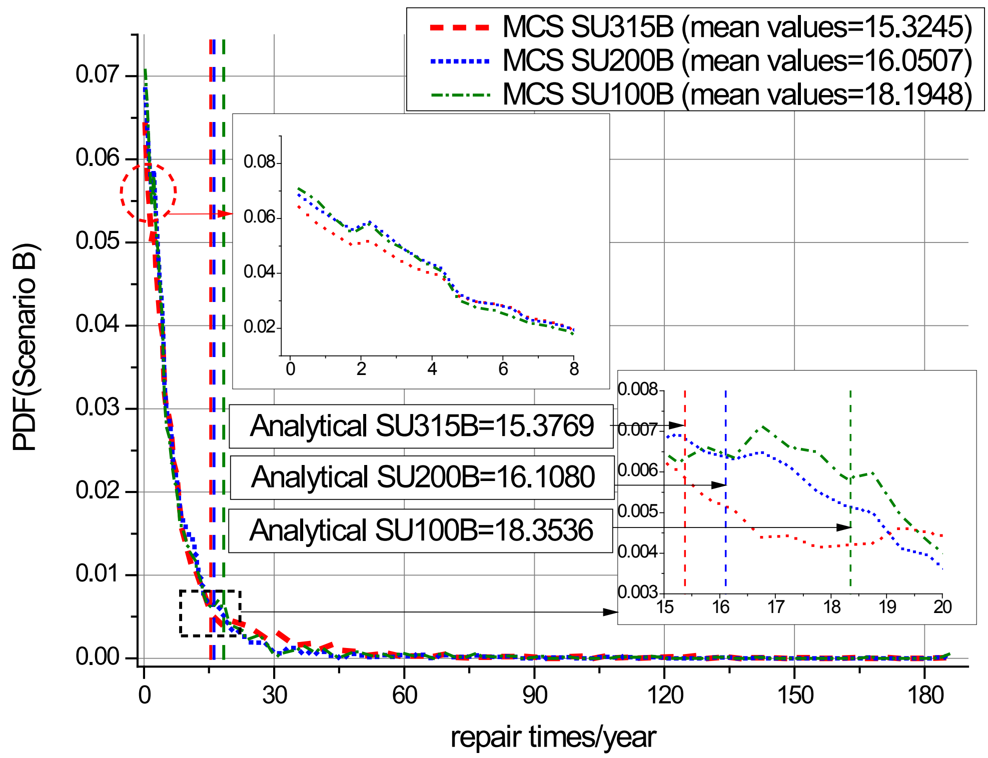
Figure 5.14: Equivalent fault rates (temporary faults resulting in SIs) for Scenario B and different sizes of network/transformers from Table 5.6 (indicated in Legend).



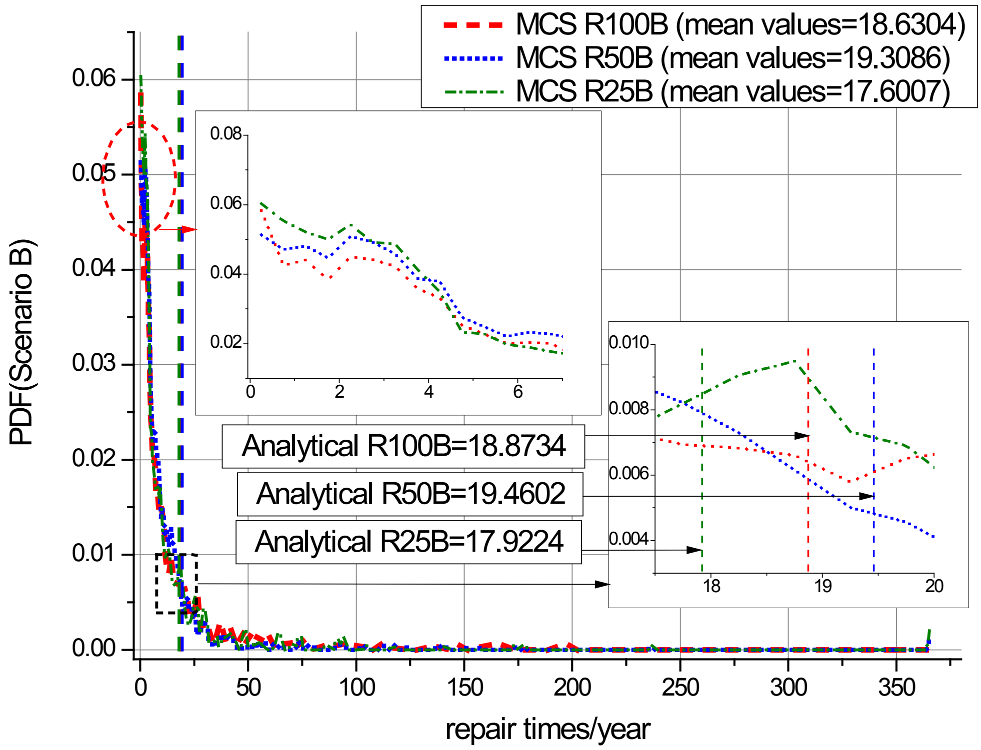
(a) highly-urban (HU)



(b) urban (U)



(c) sub-urban (SU)



(d) rural (R)

Figure 5.15: Equivalent repair times (after LIs) for Scenario B and different sizes of network/transformers from Table 5.6 (indicated in Legend).

It can be seen that the higher equivalent fault rates and repair times result in the longer tails of the distributions, i.e. in the higher expected maximum annual values of equivalent fault rates and repair times. Second, by comparing analytical and probabilistic results, the probabilistic result show the same trends as analytical result, in which the probabilities of faults decrease as the size of the supplying transformer decreases (within the same sub-sector). However, this is not the case for the rural sector, where reducing of the network size results in a strong decrease of the supplied customers.

The red dashed circles in Figs. 5.12 and 5.15 indicate the operation of the protection devices, which cause "spikes" on the PDF curves. They indicate faults that originate from protection devices (CBs and fuses), which are fully included in the presented simulations. Since some of these protection devices are used to protect larger numbers of customers, they can cause disconnection of supply for these (larger number of) customers whenever local protection device is faulty, therefore causing a noticeable “spike” on PDF curves around corresponding repair times (e.g. 3 hours for fuses). These situations are different from the permanent faults on overhead lines, which might also activate a fuse (fuse blowing), as in that case the fuse will be replaced within 3 hours, but customers will still experience a longer supply interruption due to repair times of 0.4 kV overhead lines, which is 5.7 hours (from Table 5.7).

5.3 Chapter Summary

The assessment of network reliability performance strongly depends on the availability and accuracy of the required input data, which typically (significantly) differ in e.g. urban and rural areas/networks. To correctly acknowledge this fact, the analysis in this chapter continued the approach from Chapter 4, where LV and MV distribution networks are divided into four subsectors (HU, U, SU and R) based on the location and density of customers and supplied loads. Accordingly, all required input reliability data are in this chapter considered and evaluated for the corresponding subsectors, where appropriate coefficients for recalculating fault rates and repair times are derived and applied to obtain the final values of input reliability data. Since the coefficient of fault rates only provide information on LIs (from the recorded statistics in Table 5.3), it was also necessary to obtain information for SIs.

The outcome of the analysis in this chapter are detailed information and more accurate representation of typical/generic LV networks, which are expressed in the form of reliability equivalents for the assessment of reliability performance of HV and MV networks.

Chapter 6 Reliability Analysis with Regulator Requirements, Penalty Risks and DG/ES Technologies

Practically every country with developed and mature electricity network infrastructure has formulated Security of Supply, SoS, and/or Guaranteed Standard of Performance, GSP, requirements for the reliability of their networks. Their main function is to protect residential/domestic and non-domestic customers from (too) frequent and (too) long supply interruptions. In addition, DNOs in Europe also report on their annual performance, which is assessed by the Regulators against the pre-set annual targets, resulting in penalties for low reliability performance (i.e. worse than the specified targets) or rewards for high reliability performance (i.e. better than the specified targets). However, although these requirements have been set and although the penalty/reward scheme is incentivising a continuous improvement of reliability performance (e.g. from one calendar year to another), there is still a possibility that certain customers will experience more frequent and/or more longer duration of supply interruption than those prescribed by specified targets.

Another issue is that reliability targets are usually stipulated for the overall/average network performance, through the system reliability indices (most commonly SAIFI or CI and SAIDI or CML), which means that: a) these values are related to no specific customer, as they are average system values, and b) that there will always be customers with worse/better performance than the system average values. In order to allow for a more detailed analysis of reliability performance, this chapter analyses the reliability performance requirements from the perspectives of the “worst and best served customers” in the modelled networks and also calculates the probabilities of values higher than the pre-specified targets (e.g. from the GSP), which essentially introduces the “risk of paying penalty” into the reliability analysis. Finally, the last part of this chapter is dedicated to the analysis of the potential improvement of reliability performance through the coordination and management of distributed generation (DG) and energy storage (ES) technologies, which are evaluated using the time-sequential MCS approach for assessment of their benefits.

6.1 Continuity of Supply Requirements

Regulators usually define two main continuity of supply requirements: guaranteed standards of performance (GSP) and security of supply (SoS) requirements. The former should ensure that any single customer receive at least the minimum ("guaranteed") level of continuity of supply from the DNOs. The latter monitors the performance of the DNOs at the system level and it is used as a basis for reward/penalties schemes, usually against the set targets for (system average) number of supply interruptions, per year and per customer served, (SAIFI), as well as for (system average) duration of supply interruptions, per year and per customer served, (SAIDI).

In principle, Regulators do acknowledge that it is almost impossible to avoid faults occurring in the power supply systems. Therefore, they use reliability standards and setting of performance levels for "dealing with faults", i.e. for limiting their effects and impact on supplied customers. The GSP requires DNOs to compensate end-users for each supply interruption event which is not dealt with within the maximum allowed time, or for too frequent supply interruption events. There is additional discrimination in requirements based on the number of interrupted customers, or total amount of the (un)supplied demands.

In the UK, the interruption incentive scheme has symmetric annual rewards and penalties, depending on each DNO's performance against their targets for the number of customers interrupted per 100 customers (CI) and the number of customer minutes lost (CML). The DNO's reliability performance, i.e. CI and CML indices, is audited each year and an audit report is published, detailing the accuracy of the measurements and any adjustments, if applied to their annual performance. The proportion of revenue exposed under the scheme is 1.2% for CI and 1.8% for CML.

6.1.1 The UK Security of Supply (SoS) Requirements

The UK SoS specifies the maximum prescribed times (i.e. the maximum durations of LIs) for restoring supply to at least a minimum group demand of the interrupted customers, before the involved DNO would be liable for paying a penalty, Table 6.1. Accordingly, the network configuration, the protection schemes and the actual fault restoration and repair processes of faulted network components are the main factors determining the duration of LIs. Moreover, six classes of supply are defined based on the group demand ranges for which the maximum durations of LI are correlated with the minimum demands that have to be restored in case of LIs. For example, Class A corresponds to a group demand lower than 1MW, for which interrupted supply should be restored according to the repair times of the faulted components. For all other group demands, shorter supply restoration times should be achieved by DNOs: for group demand between 1MW and 12MW, the supply restoration times are not based on the repair times of faulted components, but the supply must be restored to most of the customers within three hours. This implicitly suggests that DNOs should implement additional measures (besides prompt repairs of faulted components) for achieving the required reliability levels. Typically, these include, as discussed in previous chapters, network reconfiguration and network automation functionalities, or provision of alternative supply points.

Table6.1: Security of Supply requirements in the UK [107]

Class	Corresponding Group Demand (GD)	Required supply restoration times and minimum demands to be met after the first circuit outage
A	GD ≤ 1 MW	In repair time: GD
B	1 MW < GD ≤ 12 MW	a) Within 3 h: GD-1MW b) In repair time: GD
C	12 MW < GD ≤ 60 MW	a) Within 15 min: min{GD-12MW; 2/3 GD} b) Within 3 h: GD
D	60 MW < GD ≤ 300 MW	a) Immediately: GD-up to 20 MW b) Within 3 h: GD
E	300 MW < GD ≤ 1500 MW	Immediately: GD
F	GD > 1500 MW	According to transmission license security standard

Table 6.1 specifies the maximum durations of supply restoration times, which in most cases are significantly shorter than the network component repair times, already discussed and given in Table 5.2. Although some of the network component repair times are outside this limit and do not accrue to the specific DNO penalties, they nevertheless can affect the reliability performance of the network to be outside the specified annual targets.

Accordingly, the maximum supply restoration times shown in Table 6.1 (and Table 6.3) have been implemented in this thesis, in order to more accurately quantify the effects of different functionalities of certain network components, such as the manual or automatic control for reconfiguration, transfer to alternative supply and reclosing. It is shown that without including Regulator requirements in the reliability assessment, the calculated values will not properly reflect the practical situations, i.e. the calculated reliability indices will not be as accurate as it should be expected.

6.1.2 UK Guaranteed Standard of Performance (GSP)

The UK GSP specifies guaranteed standards of service levels that must be met by each DNO and are reasonable to expect to be delivered in all cases. If a DNO fails to meet the required level of service, it must make a payment to the customer (subject to certain exemptions). These “GSP payments” are envisaged as a compensation for the inconvenience caused by a loss of supply and are not designed to compensate customers for related financial losses (which are assessed independently).

As mentioned, the GSP is directly aimed to protect domestic (i.e. residential) and non-domestic customers from excessively long and frequent supply interruption events, i.e. those categories of customers without special contracts or agreements with the DNOs regarding LIs. Accordingly, the UK Regulator specifies requirements for the duration and the number of LIs, with [153] and [154] being the main UK statutory instruments for specifying the allowed supply restoration times for up to 5,000 customers, more than 5,000 customers, and in severe weather conditions.

This is illustrated in Table 6.2 (only for normal system operating conditions), together with the corresponding compensations that DNOs will pay directly to the customers (not to the Regulator), if supply is not restored within the time specified in [153] and [154].

Table 6.2: Guaranteed Standard of Performance (2010 Edition) in the UK [154]

<table>
<tr><td colspan="3">Supply Restoration Time</td><td colspan="2">Compensation Paid to:</td></tr>
<tr><td>No. of customers interrupted</td><td colspan="2">Maximum supply restoration time</td><td>Domestic customers</td><td>Non-domestic customers</td></tr>
<tr><td rowspan="2">< 5,000</td><td colspan="2">18 h</td><td>£54</td><td>£108</td></tr>
<tr><td colspan="2">After each succeeding 12h</td><td colspan="2">£27</td></tr>
<tr><td rowspan="3">≥ 5,000</td><td colspan="2">24 h</td><td>£54</td><td>£108</td></tr>
<tr><td colspan="2">After each succeeding 12h</td><td colspan="2">£27</td></tr>
<tr><td colspan="2">Maximum</td><td colspan="2">£216</td></tr>
<tr><td>Component Replacement</td><td colspan="2">Maximum supply restoration time</td><td colspan="2">Compensation Paid to all customers</td></tr>
<tr><td rowspan="2">Fuse</td><td>Working days</td><td>3 h</td><td colspan="2" rowspan="2">£22</td></tr>
<tr><td>Non-working days</td><td>4 h</td></tr>
<tr><td colspan="3">Multiple Interruptions</td><td colspan="2">Compensation Paid to all customers</td></tr>
<tr><td colspan="3">Four or more interruptions (≥ 4),
each lasting at least three hours (≥ 3 h)</td><td colspan="2">£54</td></tr>
</table>

Furthermore, the DNOs have to keep continuously improving their network performance by maintaining, changing, and upgrading to new technological devices and components, in order to meet the annual targets specified by the Regulator. In order to provide the best reliability performance, the UK Regulator has revised the SoS in 2015 and is now enforcing increased compensation payments and some new requirements for the maximum supply restoration times (e.g. previously allowed 18 hours limit is now reduced to 12 hours). Table 6.3 illustrates the new GSP requirements that came into force on the 1st of April 2015.

Table 6.3: Guaranteed Standard of Performance (2015 Edition) in the UK [108]

<table>
<tr><td colspan="3">Supply Restoration Time</td><td colspan="2">Compensation Paid to:</td></tr>
<tr><td>No. of customers interrupted</td><td colspan="2">Maximum supply restoration time</td><td>Domestic customers</td><td>Non-domestic customers</td></tr>
<tr><td rowspan="2">< 5,000</td><td colspan="2">12 h</td><td>£75</td><td>£150</td></tr>
<tr><td colspan="2">After each succeeding 12h</td><td colspan="2">£35</td></tr>
<tr><td rowspan="3">≥ 5,000</td><td colspan="2">24 h</td><td>£75</td><td>£150</td></tr>
<tr><td colspan="2">After each succeeding 12h</td><td colspan="2">£35</td></tr>
<tr><td colspan="2">Maximum</td><td colspan="2">£300</td></tr>
<tr><td>Component Replacement</td><td colspan="2">Maximum supply restoration time</td><td colspan="2">Compensation Paid to all customers</td></tr>
<tr><td rowspan="2">Fuse</td><td>Working days</td><td>3 h</td><td colspan="2" rowspan="2">£30</td></tr>
<tr><td>Non-working days</td><td>4 h</td></tr>
<tr><td colspan="3">Multiple Interruptions</td><td colspan="2">Compensation Paid to all customers</td></tr>
<tr><td colspan="3">Four or more interruptions (≥ 4),
each lasting at least three hours (≥ 3 h)</td><td colspan="2">£75</td></tr>
</table>

6.1.3 Comparison with Requirements in European Countries

Similarly to the requirements in the UK, Tables 6.4 and 6.5 list the Italian Supply Quality Standard (SQS-I) and the Guaranteed Standards of Performance (GSP-I), [4]-[5]. The SQS-I defines the maximum restoration times, the average number of interruptions and the average duration of interruption with a separation of inhabitant concentrations that logically defines the network sub-sectors as used in this thesis (i.e. urban, sub-urban and rural area). On the other hand, the GSP-I defines the compensation rates in accordance with the criteria for different types of customers. Table 6.6 illustrates the Regulator requirements for some other European countries.

Table 6.4: Supply Quality Standard in Italy, SQS-I [155]

Requirement	High Concentration (I > 50,000)*	Medium Concentration (5,000 < I ≤ 50,000)*	Low Concentration (I ≤ 5,000)*
Maximum supply restoration times (LV customers)	8 h	12 h	16 h
Maximum supply restoration times (MV customers)	4 h	6 h	8 h
Average number of interruptions	1 int/customer	2 int/customer	4 int/customer
Average duration of interruptions	25 min/customer	40 min/customer	60 min/customer

*I – number of inhabitants; this thesis assume that 5,000 inhabitants correspond to about 2,000 residential customers and around 5 MW of residential load demand.

Table 6.5: Guaranteed Standard of Performance in Italy, GSP-I [156]

Customers interrupted	Criteria for compensation	Compensation
Domestic	If longer than SQS-I duration limit	€30
	For each succeeding 4h	€15
	Maximum	€300
LV & MV Non-domestic Non-public ≤ 100 kW	If longer than SQS-I duration limit	€150
	For each succeeding 4h	€75
	Maximum	€1,000
LV Non-domestic Non-public > 100 kW	If longer than SQS-I duration limit	€2/kW
	For each succeeding 4h	€1/kW
	Maximum	€3,000
MV Non-public > 100 kW	If longer than SQS-I duration limit	€1.5/kW
	For each succeeding 2h	€0.75/kW
	Maximum	€6,000
LV & MV With license for generation*	If longer than SQS-I duration limit	€0.15/kW
	For each succeeding 4h	€0.075/kW
	Maximum	€3,000

*It is assumed that for prosumers (producers-consumers) the maximum compensation between producers and consumers is applied.

Table 6.6: Guaranteed Standard of Performance in some European countries

Country	Area / voltage level		No of Inter-ruption	Time of Interruption (hours)	Compensation	
Romania [157], [158]	Unplanned outage	Urban (normal weather)	-	≥12	HV (>110kV) – RON 300 (Additional RON 100 every 6h, max RON 700) MV(1kV<V≤110kV) – RON 100 (Additional RON 40 every 12h, max RON 200) LV(<1kV) – RON 30 (Additional RON 20 every 12h, max RON 100) ***cooling time for each interruption is 3 minutes	
		Rural (normal weather)		≥24		
		Urban / Rural (extreme weather)		≥72		
	Planned outage	Urban	4	Max 12h each interruption	HV (>110kV) – RON 150 MV(1kV<V≤110kV) – RON 50 LV(<1kV) – RON 15	
		Rural	8	Max 16h each interruption		
Spain (Unplanned) [159], [160]	MV (1kV<V≤36kV)	Urban (>20,000 customers)	≥8	≥4	Discount for time interruption, $D_T = 5\frac{FE}{E}P_f(T_I - U_T)$ (max 10% of energy consumption on previous year) Discount for number of interruption, $D_N = \frac{FE}{E}P_f T_I \frac{(N_I - U_N)}{8}$ (max 10% of energy consumption on previous year) Where; FE = Energy consumption billed over the previous year, as established in the regulation of 12 January 1995 for electrical tariffs. E = Annual energy supplied. P_f = Average power billed over the year. T_I = Annual interruption time accumulated. N_I = Annual number of interruptions accumulated. U_T = Time threshold of the supply zone. U_N = Threshold for number of interruptions in the supply zone.	
		Semi-Urban (2,000<C≤20,000 customers)	≥12	≥8		
		Concentrated Rural (200<C≤2,000 customers)	≥15	≥12		
		Dispersed Rural (<200 customers)	≥20	≥16		
	LV (≤1kV)	Urban (>20,000 customers)	≥12	≥6		
		Semi-Urban (2,000<C≤20,000 customers)	≥15	≥10		
		Concentrated Rural (200<C≤2,000 customers)	≥18	≥15		
		Dispersed Rural (<200 customers)	≥24	≥20		
Netherlands (Unplanned) [161], [162]	240 / 400V		-	≥4	EUR 35	
	400<Voltage≤20kV			≥4	EUR 910	
	≥20kV			≥4	EUR 0.35/kW (max EUR 91,000)	
Sweden (Unplanned) [163], [164]	Not specified in Swedish Electricity Act		-	12≤T<24	12.5% of tariff a, minimum 2% of b	Where; a = individual customer annual network tariff b = yearly set base amount (for 2007, Swedish Government set it to SEK 41,100) -max up to 300% of tariff a for one outage period cooling period is (2 hours)
			-	24≤T<48	37.5% of tariff a, minimum 4% of b	
			-	48≤T<72	62.5% of tariff a, minimum 2% of b	
			-	Any subsequent of 24 hours	+25% of tariff a, +2% of b	

6.1.4 Supply Restoration Time after Temporary Faults

One of the important requirements for the correct implementation of reliability assessment methods is a clear (or as clear as possible) separation of customer supply interruptions into SIs and LIs. This requires to accurately model activation and operation of certain network protection devices (in different protection schemes) that typically have an impact on the supply restoration times. For example, a permanent fault of a network component may not result in a LI, but in a SI, if the network is reconfigured to provide alternative supply to all affected customers within 3 minutes (in Europe) or 1 minute (in the US). The opposite is also true for certain protection components: a temporary fault may not result in SI, but in a LI, when a fuse is activated by a temporary fault and manual intervention is required to restore the supply (i.e. to replace the fuse). In other words, the calculation of LIs should also include temporary faults that contribute to LIs due to the settings and characteristics of the protection systems. This is applied in the analysis presented in this chapter, where the typical values from Table 6.7 for the protection components in the UK are used to model fault clearing times and their effects on the calculated reliability indices.

Table 6.7: Typical Fault Clearing Times in UK [71, 92]

Power Component	Voltage Level (kV)	Protection System	Fault clearing time (s)
Overhead Lines	11	Circuit breaker with auto-reclosing	10-120
	33	Circuit breaker with auto-reclosing	90
Cables	11	Circuit breaker with auto-reclosing	up to 3
	33	Circuit breaker with auto-reclosing	90
Transformers	11/0.4	Fuse	repair time
	33/11	Circuit breaker with auto-reclosing	0.15-10
Buses	0.4	Fuse	repair time
	11	Circuit breaker	0.15
	33	Circuit breaker	0.15

6.2 Assessment of Penalty and Compensation Risks

Network reliability performance is one of the most important criteria in designing, planning, operating, maintaining and upgrading the power supply systems. Generally, the DNOs put significant efforts aimed at providing power supply to their customers with certain reliability levels, e.g. based on the annual targets imposed by the Regulators, or on the GSP requirements. At the same time, the DNOs have two other equally important objectives: to provide a low cost power supply to customers and to reduce the (capital and maintenance) costs of operating their networks. As the improved reliability levels usually come with the higher investment and operation costs (therefore resulting in higher costs for customers), these objectives are conflicting, requiring careful planning by the DNOs.

However, and as mentioned before, the recent statistics from the UK suggest that maintaining the highest possible reliability levels with as low cost to the customers as possible is not an easy task. In one year, 14% of the UK DNOs have been penalised by the Regulator for not achieving their annual targets for customer interruption (CI) index, while 50% of DNOs were penalized for exceeding their annual targets for customer minutes lost (CML) index, [6].

Inefficient DNOs' reliability planning strategies may result in reliability performance of their network being below the annual targets, when involved DNOs will pay penalties. Therefore, DNOs need to carefully decide on the level of reliability investments and expected return of these investments, in terms of the achieved reliability improvements against the level of penalty payments in cases when specified targets are not met. Accordingly, among the several possible reasons for the abovementioned penalisation of a large number of the UK DNOs (e.g. a higher fault exposure in that particular year), one reason might be that the DNOs are not using the most robust, accurate and flexible reliability assessment procedures for the correct evaluation of (variations in the expected) reliability performance in terms of frequency and duration of LIs.

It could be generally concluded that the assessment of reliability performance of modern networks requires to use sophisticated probabilistic procedures, i.e. Monte-Carlo Simulations (MCS) instead of analytical approaches, as this will allow to correctly estimate the ranges of variations of reliability indicators. Furthermore, it is very important to provide accurate input reliability data, parameters and network models, which should be then correctly implemented in related probabilistic/MCS assessment approaches. Up to this point, this thesis discussed, implemented and demonstrated a number of possible improvements of reliability assessment procedures. This chapter continues further, by including in the presented generic network methodology the following factors: a) reliability targets imposed by the Regulator, b) assessment of performance of the worst/best served customers, and c) by evaluating impact of distributed generation and energy storage technologies.

First, the previously discussed penalty limits/thresholds defined by the UK Regulator have been assessed and then applied as a criteria for quantify the risk of paying the penalty or compensation by the DNOs. Afterwards, the characteristics and settings of protection systems from Table 6.7 and related SoS requirements are also included in the analysis, where the calculated LI and SI results again include all four generic LV distribution networks.

In the analysis, the three general cases are defined, Table 6.8, based on the use of LV protection devices. These cases reflect both the fact that the DNOs are improving their network reliability performance on an annual basis (e.g. by employing new and more sophisticated protection devices), and the fact that the Regulator constantly enforces new and more stringent requirements for the DNOs' reliability performance.

Table 6.8: Description of three cases selected for the analysis

Case	Description
1	Z1/Z2 changes to fuses and Z3 change to CB in Figures 4.1-4.8.
2	Protection systems are the same within Figures 4.1-4.8.
3	Z1/Z3 changes to smart fuses and Z2 changes to CB in Figures 4.1-4.8.

In the presented analysis, one recently introduced protection device is included in Case 3: "smart fuse", [43]. A smart fuse is aimed at improving both the reliability performance and power quality performance, as it has two cartridges instead of only one, where the activation of the first cartridge due to a transient fault does not result in the supply interruption, as the second/reserve cartridge is automatically placed to preserve the supply. In that way, a smart fuse is similar to a CB with one reclosing operation followed by a disconnection (the second cartridge will blow in the case of a permanent fault), but a smart fuse is assumed to have lower fault rates and mean repair times, i.e. as the standard fuse. (It should be noted that the application of smart fuses was relatively new and that no input data have been available for fault rates and repair times at the time of writing this thesis. Due to similarities in construction, the fault rates and repair times of smart fuses are assumed to be similar to the standard fuses, as given in Tables 5.1 and 5.2).

The presented analysis and obtained results concern both reliability performance (number of long interruptions, LIs, and their duration) and power quality performance (number of short interruptions, SIs). Generally, both the actual type of the fault and the applied fault-response scheme will define the type of the resulting interruption (LI vs SI). While presented analysis still uses separation of faults in only permanent and transient faults, it should be noted that the following four general types (or stages) of fault development are defined in [43]:

- Transient fault (irregular voltage dip that typically does not cause fuse operation)
- Intermittent fault (causes irregular fuse operations)
- Continuous fault (causes repetitive fuse operations)
- Permanent fault (activate/blow the fuse)

From the power quality point of view, transient, intermittent and continuous faults are categorized as short interruptions, and permanent faults as long interruptions. Although the intermittent and continuous faults are categorized as short interruption faults, if they results in the activation of the fuse, and if the fuse is replaced manually, this will take more than 3 minutes, resulting in a long interruption. Therefore, by changing the protection devices (from a fuse to a CB), intermittent and continuous faults will be still categorized/grouped as short interruptions (by assuming that the CB will open faster than the fuse and will be able to reclose in case of temporary faults, i.e. short interruptions).

The results for all three cases and all four generic types of LV networks from Figs. 4.1-4.8 are presented in Table 6.9.

Table 6.9: The results for calculated reliability indices (mean values) for the three selected cases and all generic networks.

Case	Network Type	SAIFI	MAIFI	SAIDI	CAIDI	ENS
1	HU	0.0192	0.0210	0.1239	6.4442	0.1618
	U	0.0238	0.0305	0.3039	12.7544	0.3966
	SU	0.0292	0.0657	0.3721	12.7292	0.4587
	R	0.0288	0.0911	0.4543	15.7756	0.5929
2	HU	0.0208	0.0222	0.1883	9.0676	0.2457
	U	0.0254	0.0232	0.3734	14.7206	0.4873
	SU	0.0311	0.0694	0.4772	15.3245	0.6229
	R	0.0314	0.0986	0.5858	18.6304	0.7646
3	HU	0.0175	0.0235	0.1223	6.9990	0.1596
	U	0.0222	0.0333	0.3008	13.5558	0.3926
	SU	0.0269	0.0675	0.3719	13.7983	0.4854
	R	0.0263	0.0947	0.4445	16.8783	0.5802

In Case 1, the fuses within the network are the only protection devices for isolating the faulted part from the healthy network. This case is referred to as the base case, in order to quantify the possible improvements of reliability performance by replacing fuses with more sophisticated (and more expensive) protection devices. In Case 2, when some of the fuses are replaced with CBs, the reliability performance did not improve, as the fault rates and repair times of CBs are higher than that of the fuses, cancelling effects of more efficient handling of temporary faults. In Case 3, when fuses are replaced with smart fuses, an improvement of reliability performance of around 12.5% for SAIFI and a bit lower improvement of SAIDI is achieved (but not for CAIDI, as CAIDI=SAIDI/SAIFI).

6.2.1 Penalty/Compensation Risks for Average Customer

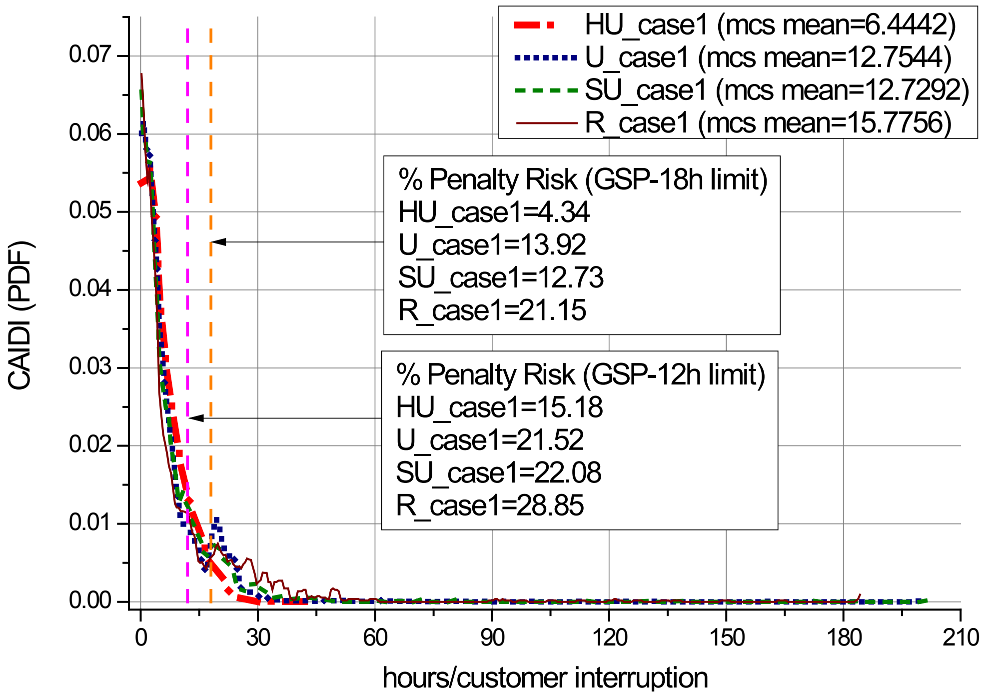
As previously discussed, the GSP requires DNOs to restore interrupted supply within a specified period of time or, otherwise, DNOs must pay compensations directly to the affected customers. Here, the use of the probabilistic (MCS) reliability approaches allows to directly assess the penalty risks, as the output distributions of, e.g. mean repair times (i.e. average duration of LIs), explicitly give the probabilities of LI events with durations longer than the specified GSP time limits. In the case of the UK GSP, the time limits for compensation payments are 12 hours (2015 edition, Table 6.3) and 18 hours (2010 edition, Table 6.2). The results in this section refer to "average customer", i.e. to the mean values calculated for the total number of served customers, while the next section provides the results for the actual worst- and best-served customers from all generic networks.

Table 6.10 presents the results for the estimated penalty risks for the four generic networks and Cases 1 to 3. Higher repair times of CBs contributed to the increased values of SAIDI, CAIDI and ENS indices. The presented results also indicate how the recent change of maximum restoration time from 18 hours to 12 hours is placing an increased stress on the DNOs, as the risks of paying penalties are in some cases increasing three times. It is also indicative that the change of protection devices from fuses to CBs and then to smart fuses is actually not reducing the penalty risks, but it is opposite – the risk is increasing, except in SU and R networks, where percentage of temporary faults is higher, therefore justifying the installation of CBs and smart fuses for the supply restoration time limit of 18 hours, but not for the new restoration time limit of 12 hours. This is an important result, which additionally justifies the use of probabilistic reliability assessment approaches, as the improvement in mean values in Table 6.9 could be misleading with respect to the (expected) reduction of penalty risks. From the "average customer point of view", the GSP-related reduction of the maximum restoration time from 18 hours to 12 hours is certainly reflecting an improved reliability performance, but from the DNOs' perspective, this might present too high operational and investment requirements in satisfying the target limits set by the Regulator.

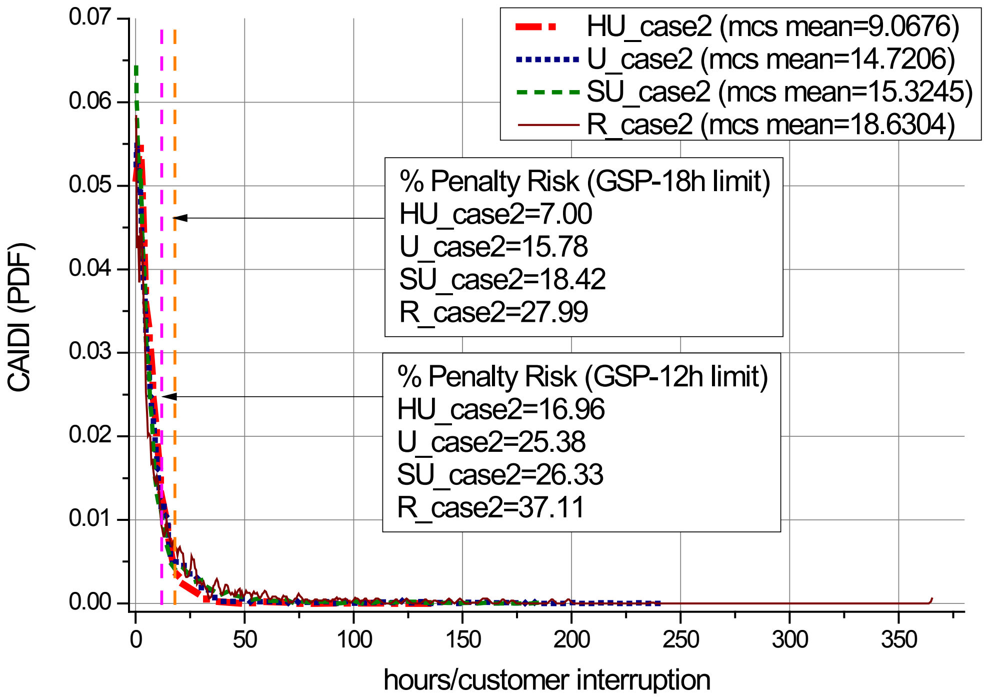
Table 6.10: The results for calculated/estimated penalty risks for the duration of LIs for three selected cases and all generic networks (% of LIs with durations longer than 12 hours or 18 hours).

GSP limit	Network Area	HU	U	SU	R
18 hours	Case 1	4.34	13.92	12.73	21.15
	Case 2	7.00	15.78	18.42	27.99
	Case 3	5.80	12.72	14.99	20.21
12 hours	Case 1	15.18	21.52	22.08	28.85
	Case 2	16.96	25.33	26.38	37.11
	Case 3	15.00	21.91	24.16	32.98

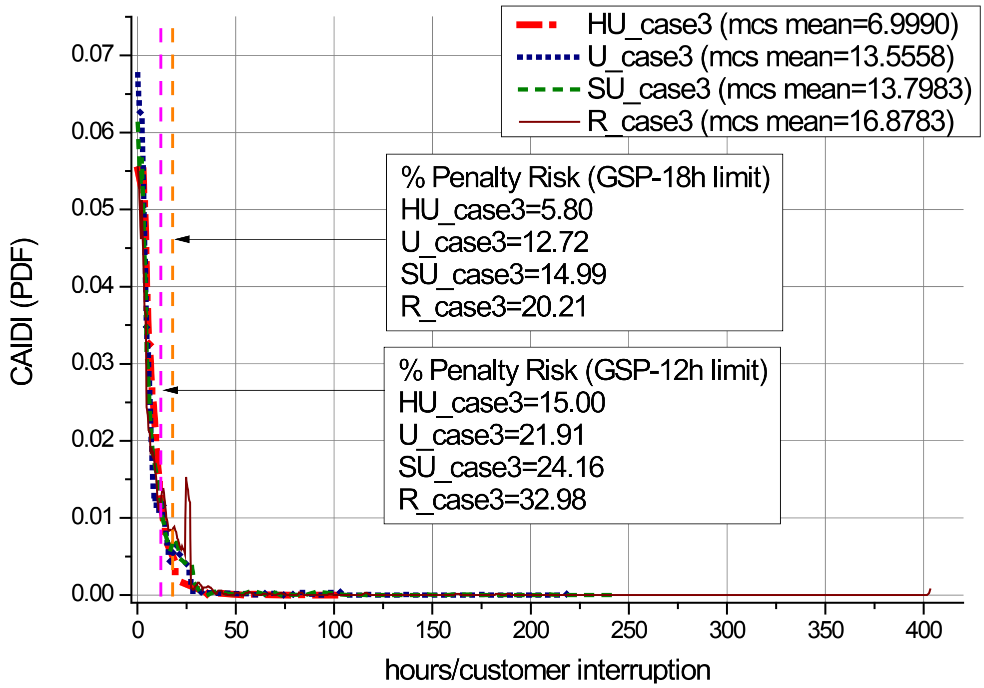
The results in Table 6.10 are obtained from the probability distributions (PDFs) CAIDI curves in Fig. 6.1, where 12 hours and 18 hours LI duration limits from the UK GSP are plotted as vertical lines and used for calculating risk of paying compensation.



a) Case 1



b) Case 2



c) Case 3

Figure 6.1: Probability distributions of CAIDI for assessing risks of penalty (average customer)

6.2.2 Penalty Risks for Best and Worst-Served Customers

The annual reports that the DNOs send to the Regulator specify their network reliability performance in terms of “system-average” indices: SAIFI (or CI), MAIFI, SAIDI (or CML), CAIDI, etc. It is generally accepted that the reporting of these values is sufficient to represent the overall network performance, regardless of the fact that a number of customers will experience both lower and higher reliability performance levels than those reported by the average system indices. Effectively, these values represent a fictitious “average customer” and do not provide any information regarding the actual customers, e.g. the best-served and the worst-served customers. Therefore, it is also important for the DNOs to evaluate the ranges of variations of reliability performance levels of their customers and locate parts of the networks (typically supplying the worst-served customers) where reliability should be improved. This is discussed next, using Fig. 6.2 as an illustration.

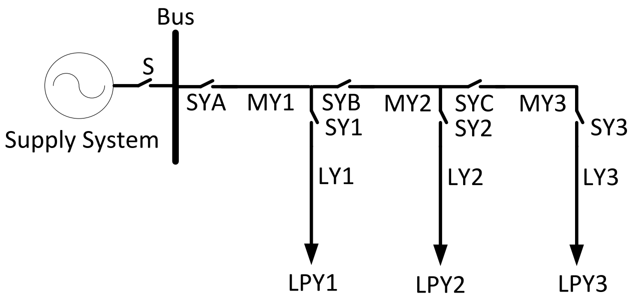


Figure 6.2: Example network for illustrating representation of best, average and worst served customers

The reliability performances of the best- and the worst-served customers should be quantified separately for the frequency of supply interruptions and for the duration of supply interruptions, as in the general case the same customer might not be exposed to the most frequent and the longest LIs. It is also possible to quantify the total duration of all interruptions for every served customer, i.e. to multiply frequency and average duration of LIs for every customer, in order to find conditions for simultaneous duration-frequency best/worst-served customer, but this is not done in this thesis.

For the calculation of the frequency and duration of LIs of individual customers in the example network from Fig. 6.2, the equations (5.5-5.17) from Chapter 5 are used and adjusted for the protection system operating without fuse-saving scheme:

The equivalent fault rates for the three indicated load points are:

$$\lambda_{LPY1} = \lambda_S + \lambda_{SYA} + \lambda_{MY1} + \lambda_{SY1} + \lambda_{LY1} \tag{6.1}$$

$$\lambda_{LPY2} = \lambda_S + \lambda_{SYA} + \lambda_{MY1} + \lambda_{SYB} + \lambda_{MY2} + \lambda_{SY2} + \lambda_{LY2} \tag{6.2}$$

$$\lambda_{LPY3} = \lambda_S + \lambda_{SYA} + \lambda_{MY1} + \lambda_{SYB} + \lambda_{MY2} + \lambda_{SYC} + \lambda_{MY3} + \lambda_{SY3} + \lambda_{LY3} \tag{6.3}$$

The equivalent load points repair times are :

$$r_{LPY1} = \frac{\lambda_S r_S + \lambda_{SYA} r_{SYA} + \lambda_{MY1} r_{MY1} + \lambda_{SY1} r_{SY1} + \lambda_{LY1} r_{LY1}}{\lambda_S + \lambda_{SYA} + \lambda_{MY1} + \lambda_{SY1} + \lambda_{LY1}} \tag{6.4}$$

$$r_{LPY2} = \frac{\lambda_S r_S + \lambda_{SYA} r_{SYA} + \lambda_{MY1} r_{MY1} + \lambda_{SYB} r_{SYB} + \lambda_{MY2} r_{MY2} + \lambda_{SY2} r_{SY2} + \lambda_{LY2} r_{LY2}}{\lambda_S + \lambda_{SYA} + \lambda_{MY1} + \lambda_{SYB} + \lambda_{MY2} + \lambda_{SY2} + \lambda_{LY2}} \quad (6.5)$$

$$r_{LPY3} = \frac{\lambda_S r_S + \lambda_{SYA} r_{SYA} + \lambda_{MY1} r_{MY1} + \lambda_{SYB} r_{SYB} + \lambda_{MY2} r_{MY2} + \lambda_{SYC} r_{SYC} + \lambda_{MY3} r_{MY3} + \lambda_{SY3} r_{SY3} + \lambda_{LY3} r_{LY3}}{\lambda_S + \lambda_{SYA} + \lambda_{MY1} + \lambda_{SYB} + \lambda_{MY2} + \lambda_{SYC} + \lambda_{MY3} + \lambda_{SY3} + \lambda_{LY3}} \quad (6.6)$$

The above equations for the fault rates and repair times of individual load points allow to identify the best- and the worst-served customers for each of these two conditions. In terms of the fault rates, load point LPY1 is the best-served customer, as it has the minimum value of the equivalent fault rate, while LPY3 is the worst-served customer, with the maximum value of the equivalent fault rate. For the LI frequency condition, it is rather easy to identify the load points for the best- and the worst-served customers, as the values of the equivalent fault rates increase proportionally with the number of components between the load point and main network supply system.

For the LI duration condition, however, the situation is opposite. The main reasons for that are: a) the increased equivalent fault rate (SAIFI) values for the load points farther away from the main supply system are in the denominator of CAIDI, equation (2.12), which effectively results in the lower CAIDI values, and b) mean repair times of components farther away from the main supply system are shorter (e.g. fuses) than the repair times of the components nearer the main supply system (e.g. circuit breakers), which results in the lower equivalent repair time (SAIDI) values in the numerator of CAIDI, same equation (2.12). Accordingly, the best-served customer in the example network in terms of average duration of LIs (CAIDI) is LPY3 (worst-served for LI frequency), whereas the worst-served customer is LPY1 (best-served for LI frequency).

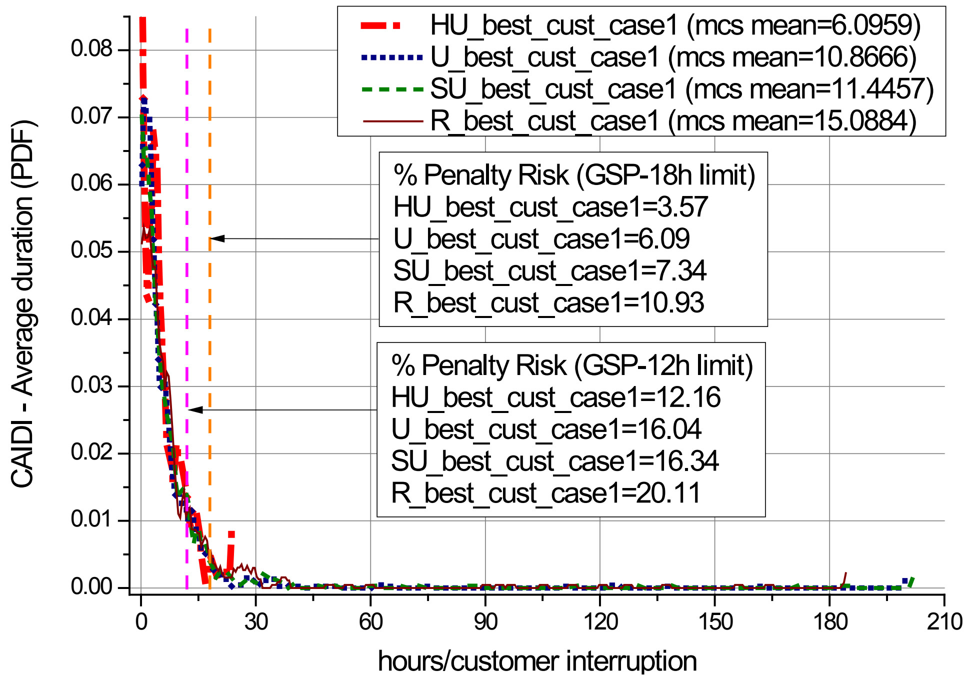
The results for the worst/best-served customer analysis in Tables 6.11 and 6.12 again use the same input data, network models and parameters as in the previous section. Table 6.11 illustrates that the worst-served customers have higher average duration of LIs, resulting in an increase of penalty/compensation risk in Table 6.12. The actual probability distributions of CAIDI values for all three considered cases (from which risks of penalty are estimated) are given in Fig. 6.3.

Table 6.11: Average duration of LIs for the best-, average- and the worst-served customers.

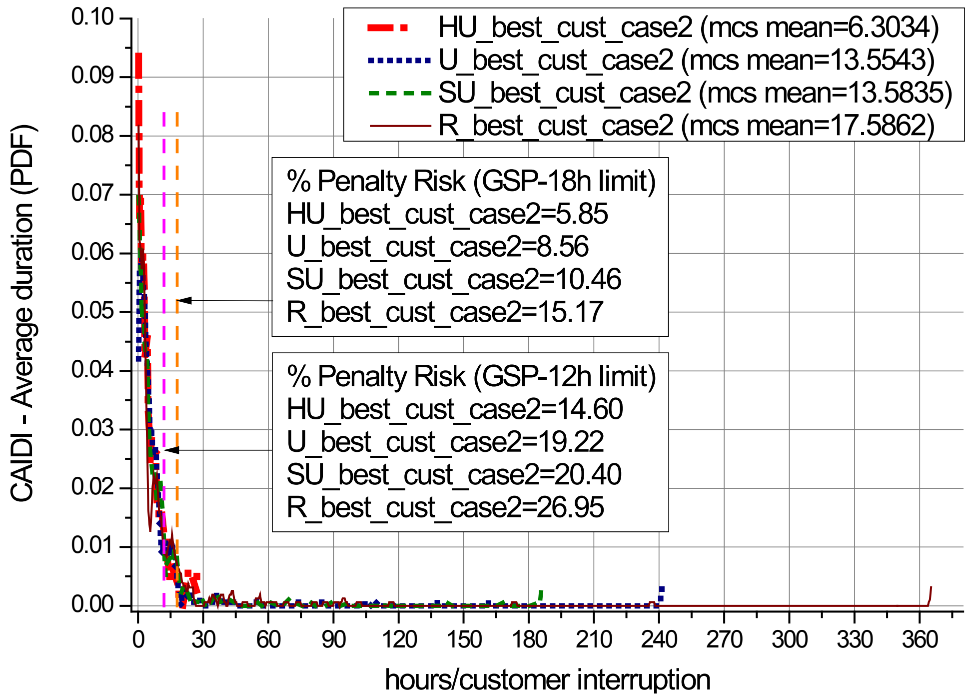
Customer	Case	HU	U	SU	R
Best	1	6.0959	10.8666	11.4457	15.0884
	2	6.3034	13.5543	13.5835	17.5862
	3	6.0596	11.1391	12.4456	16.0592
Worst	1	6.6956	15.8120	14.8511	16.6177
	2	10.7743	17.3813	18.1652	19.6176
	3	9.0147	15.7104	16.4493	17.6697
Average	1	6.4442	12.7544	12.7292	15.7756
	2	9.0676	14.7206	15.3245	18.6304
	3	6.9990	13.5558	13.7983	16.8783

Table 6.12: Penalty risks for 18 hours and 12 hours LI duration limits (in percentages) for the best-, average- and the worst-served customers.

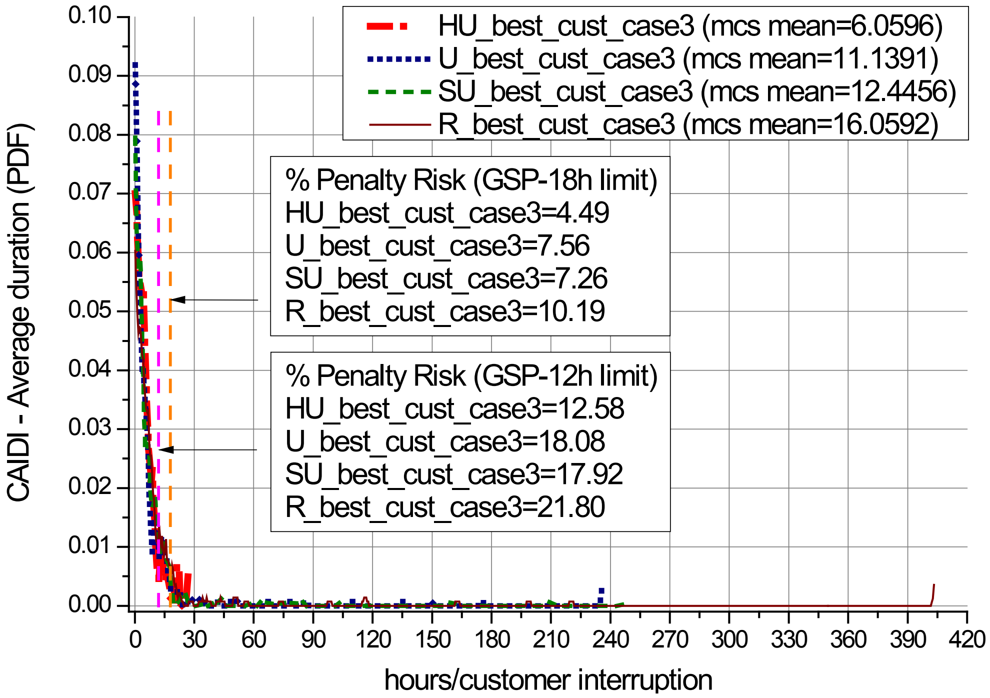
Customer	GSP limit	Network Area	HU	U	SU	R
Best	18 hours	Case 1	3.57	6.09	7.34	10.93
		Case 2	5.85	8.56	10.46	15.17
		Case 3	4.49	7.56	7.26	10.19
	12 hours	Case 1	12.16	16.04	16.34	20.11
		Case 2	14.60	19.22	20.40	26.95
		Case 3	12.58	18.08	17.92	21.80
Worst	18 hours	Case 1	6.67	22.49	17.79	24.34
		Case 2	15.86	25.64	27.43	29.11
		Case 3	12.29	21.12	21.35	22.59
	12 hours	Case 1	17.14	31.36	26.44	32.70
		Case 2	23.79	35.39	35.02	40.07
		Case 3	20.11	31.06	29.17	35.16
Average	18 hours	Case 1	4.34	13.92	12.73	21.15
		Case 2	7.00	15.78	18.42	27.99
		Case 3	5.80	12.72	14.99	20.21
	12 hours	Case 1	15.18	21.52	22.08	28.85
		Case 2	16.96	25.33	26.38	37.11
		Case 3	15.00	21.91	24.16	32.98



a) Case 1

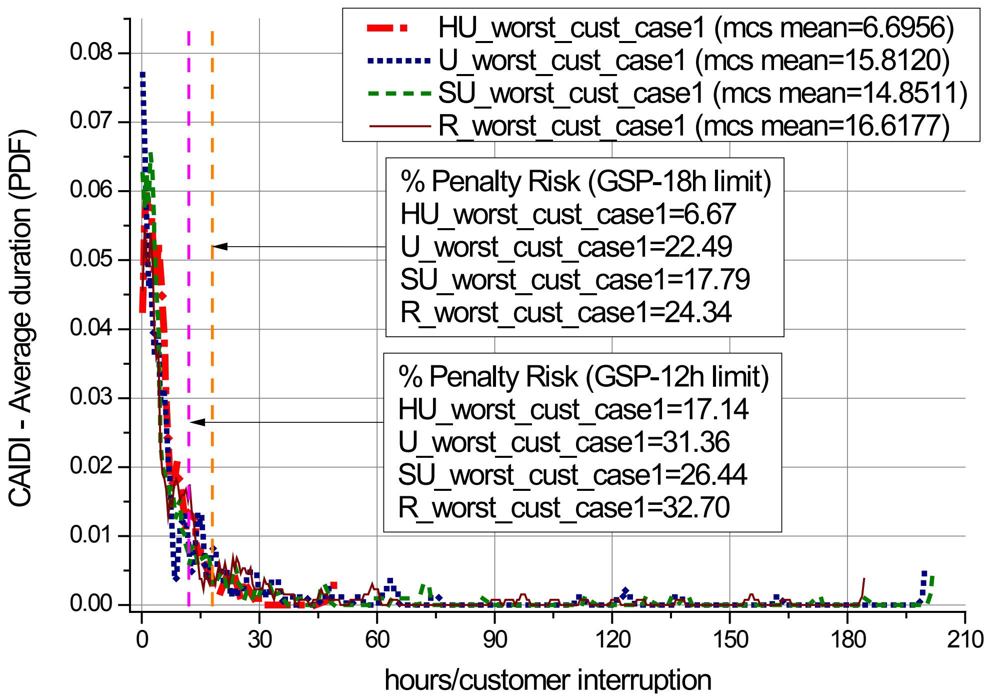


b) Case 2

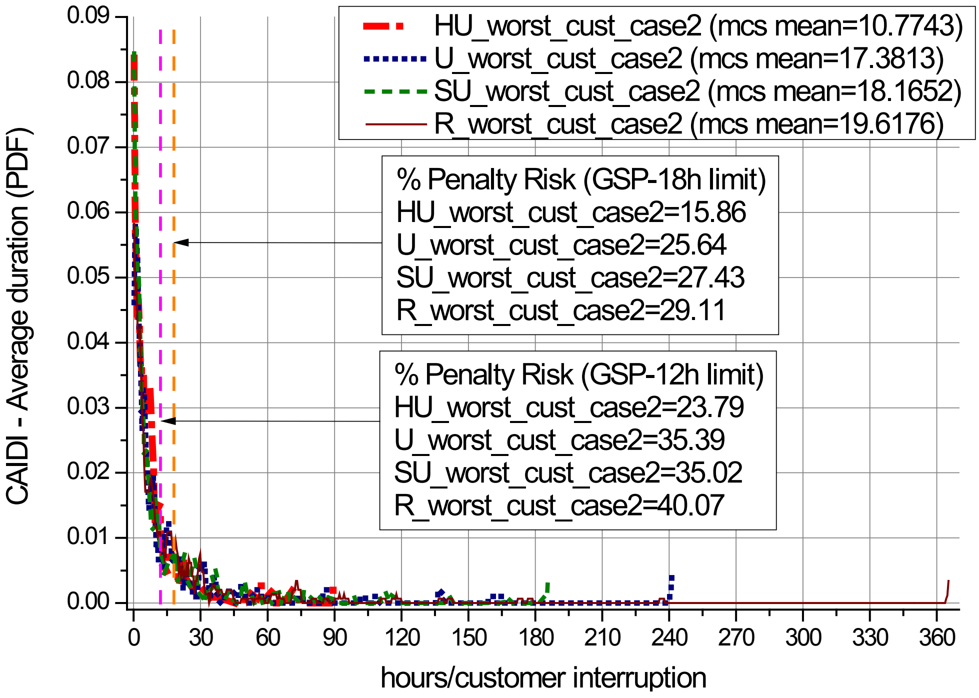


c) Case 3

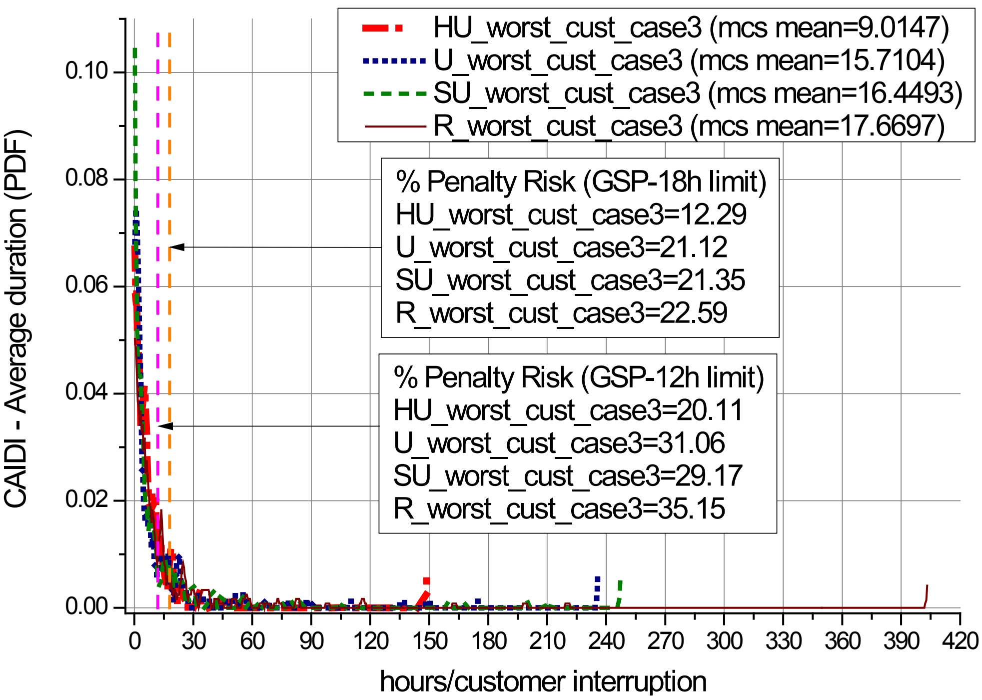
Figure 6.3: Average duration of LIs (CAIDI) for the best-served customers



a) Case 1



b) Case 2



c) Case 3

Figure 6.4: Average duration of LIs (CAIDI) for the worst-served customers

6.3 Impact of Distributed Generation and Energy Storage on Distribution Network Reliability

This section introduces distributed generation (DG) and energy storage (ES) in the analysis of reliability performance of generic LV distribution networks, where again best-, average- and worst-served customers are identified and assessed. There are two general types of DG with respect to input energy resources: a) renewable-based, such as solar, i.e. photovoltaic (PV), or wind, and b) fossil fuel-based, such as natural gas or diesel-fired. Although ES systems have merits on their own, e.g. for grid-charging when electricity cost is low (during the night) and discharging when the cost is high (during peak demand hours), this thesis analyses only dedicated ES, which is assumed to operate together with renewable-based micro and small-scale DG in LV distribution networks. The primary function of such ES systems is to balance variations in the outputs of typically PV and wind DG, which are the most common types of renewable DG in the majority of European countries, including the UK, but also elsewhere.

The presented analysis is divided in parts representing operation of DG without ES, as well as operation of both DG and dedicated ES for various target applications. It should be noted that the analysis does not include optimal sizing of ES for specific level of DG penetration, but it simply assumes that ES can take as much as the whole daily output of a variable renewable DG unit, store it and then discharge it at a suitable time (e.g. during the peak demand hours, or when a fault occurs in the network). In that way, the impact of DG with/without ES on the network reliability performance is analysed and illustrated with the obtained results.

As a part of the efforts in reducing overall CO2 emission from energy generation sector and meeting the target of 80% reduction of CO2 emission by 2050 [2], the UK government had introduced the feed-in tariff (FIT) in 2010, as an incentive specifically aimed at small-scale renewable DG applications [32]. This initiative has been especially successful for PV technologies, as at the end of 2016 more than

10GW of small PV systems were installed, mostly in residential households, with an average rated power of individual PV systems of around 4 kW.

Scotland has set an even more ambitious target, that 100% of electricity demands will be met from renewable energy resources by 2020. The UK as a whole plans to explore great potential for offshore and onshore wind-based generation and it is estimated that up to 30 GW of wind installations at all scales could be installed in the UK by 2020 [165]. Currently, more than 500MW of small and medium scale wind DG is already installed in south of Scotland alone, [166]. Similar trends are present in other EU countries, with EU currently trying to establish a target of 400 GW of installed PV capacity by 2020 [167]. The above figures and trends clearly indicate the importance of analysing the effects of renewable-based generation, including micro, small and medium--scale DG in LV and MV distribution networks, which is in this thesis addressed through the evaluation of their impact on reliability performance.

The strongest impact of DG with/without ES would be operation in so called "islanded mode", when available generation and storage capacities are coordinated to balance load in a part of the network that continues to operate after a fault in the upstream network. This mode of operation is particularly challenging in the case of DG using renewable energy resources (RER), as their outputs vary based on the changes in input RER, therefore making balancing of variable demands of supplied customers a very difficult task. Presence of ES can help in reducing variations of renewable DG outputs, e.g. to maintain the output of the combined DG-ES system around the average RER levels, where higher than average DG outputs are stored in ES, which is discharged when DG outputs are lower than the average value. The analysis described and illustrated in this section evaluates possible improvements of reliability performance due to the DG with and without dedicated ES.

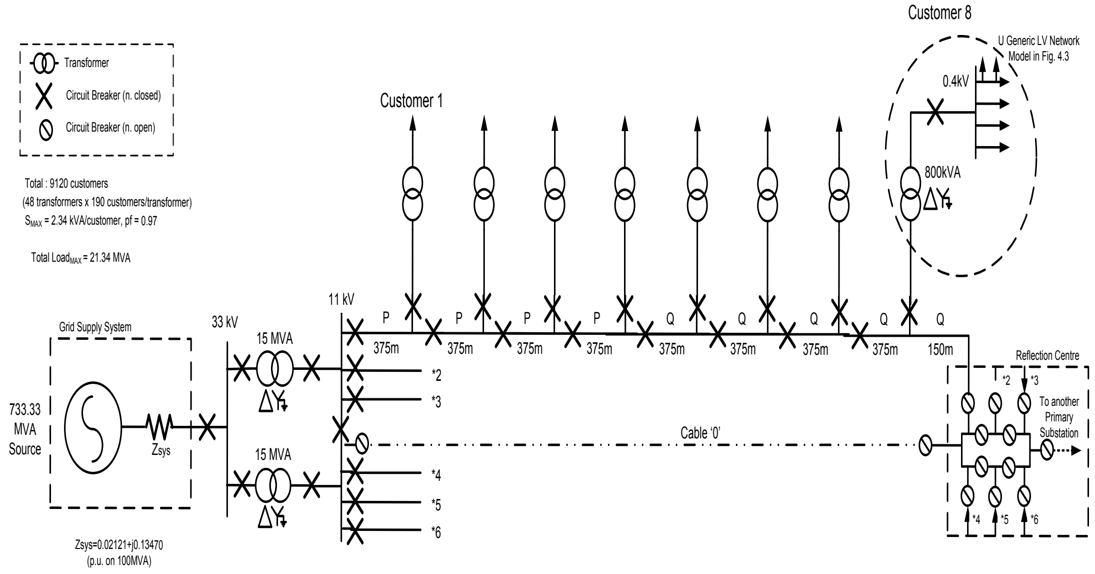


Figure 6.5: Generic MV urban network from Chapter 4.

The test network used to illustrate the reliability analysis with DG and ES is the same generic UK urban MV distribution network (Fig. 4.11 in Chapter 4), supplying LV residential customers, as illustrated in Figs. 6.5 and 6.6. The urban network is selected for the analysis as it has high density of demand and high requirements for reliability performance. By incorporating DG within the urban network, the thermal loading of component will be reduced, as part of the loads will be supplied by DG), thus reducing the probability of faults and deferring investments in network expansion as the loads/customers increase in the future. Due to restriction of available space, main types of DG that can be employed in urban network are PV, micro-CHP and micro-wind.

The urban MV network is meshed, but it is normally operated radially (CBs between two radial feeders enable change between meshed and radial configurations), Fig. 6.5. This MV network is also supported by an alternative supply point at 11kV at the end of radial feeders, assumed to provide limited support. Total of 48 MV load points (eight per feeder) are connected through 800kVA 11/0.4kV transformers, each supplying an identical generic LV radial urban network with 190 individual LV customers, Fig. 6.6. This LV network is operated in radial configuration and protected by CBs on both sides of a secondary 11/0.4 kV distribution transformer. This is an underground cable network, with each lateral spur/feeder connected to LV pillars, containing fuse or CB for isolating faults.

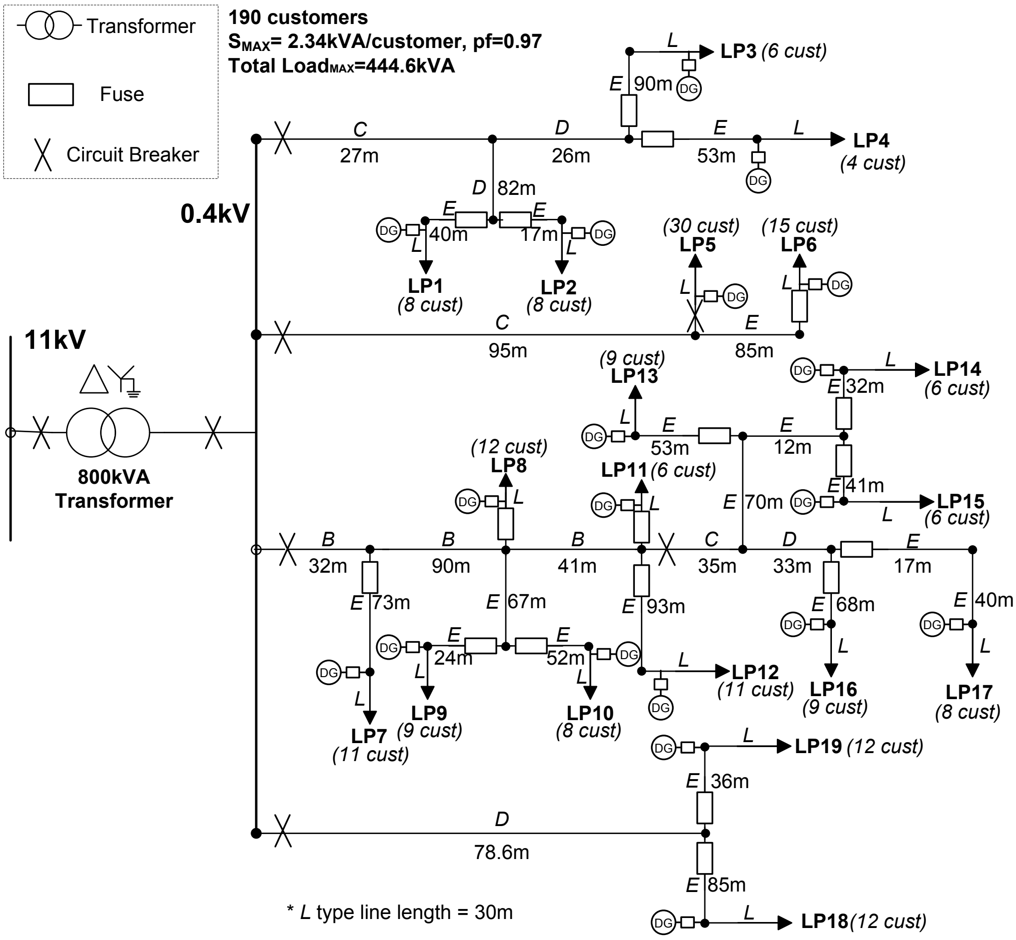


Figure 6.6: Generic LV urban network from Chapter 4 with DG connections.

In the event of a permanent fault, the faulted part of the network will be disconnected from the healthy part by the corresponding protection devices. The DNO would then take corrective action, either by manual or automatic reconfiguration and/or reconnection to alternative supply point, in order to maintain supply to most of the customers, if not all of them. However, this is not always possible due to the design limitations, as MV distribution networks are generally not designed with 'N-1' security criteria. As a result, part of the previously normally supplied load would be disconnected, in order to maintain supply to the healthy part of the network and to prevent overloading of network components, typically resulting in long interruption of the affected residential customers. In such cases, DG outputs will reduce the load in the distribution network, which means that more loads/customers will be supplied if the alternative supply point can provide only limited support.

As discussed, application of ES will reduce variations of DG outputs, which then might be able to help to provide continuous supply to a substantially higher number of customers. Although the amount of actually provided DG/ES support will depend on several factors (e.g. loading conditions, (average) outputs of DG, energy stored in ES, etc.), the impact will always be positive and will help to improve the reliability performance of the network.

Furthermore, DG connected at some network locations will have higher impact than the same DG connected at the other network locations. This opens the question of the "optimal placement of DG", but it should be noted that the DNOs have little to no impact on DG placement, as DG units are owned, installed and operated by individual customers/users, based on, e.g. their investment plans, availability of land, access to RER, etc. However, DNOs can incentivise or subsidise certain network locations to DG developers, and therefore, at least to some extent, influence the selection of the locations of DG systems in their networks.

Regardless whether it is optimally located or not, DG and ES can help to (significantly) improve network voltage regulation (particularly in weak networks), to reduce system losses (unless there are excessive reversed power flows) and to improve overall network performance, including system reliability levels. A number of previous studies have developed different methodologies for optimal placement of DG, which is usually in the weakest parts of the distribution networks. Most of the related literature implements voltage sensitivity, loss sensitivity [168] or 2/3 of the maximum load rule [169] as the main factors in deciding on (optimal) placing and sizing of DG. Although most of existing literature states or documents that selection of DG based on these criteria (voltage, loss or 2/3 of maximum load rule) will improve network reliability performance, this was actually a secondary effect of some other main criteria used for the DG placement. Accordingly, a very few studies have previously concentrated on the problem of (optimal) placement and operation of DG and ES systems with primary function to improve reliability performance of the network, e.g. [5, 113, 170]. In order to fill this gap, the analysis in this section applies improvement of reliability performance as one of the criteria for studying impact of DG location and tries to identify these load points where connected DG will have the most beneficial impact.

The first set of results is calculated using the MCS approach, showing the frequency and duration of LIs at selected load points in the considered urban generic MV network for the base case (without any DG in LV network), in order to determine the locations of the load points in the MV network where reliability indices (SAIFI and SAIDI/CAIDI) are the lowest/highest. This basically corresponds to the previous analysis of the best- and worst-served customers, but now for MV load points. For instance, Figures 6.7 and 6.8 show the probability distributions of LIs for the best- and worst-served customers (i.e. corresponding best/worst MV load points) in terms of frequency and duration of LI, respectively. As expected, the customers/load points located farther away from the MV substation (as illustrated Fig. 6.5, where load points are marked from “Customer 1” to “Customer 8”) will experience both higher frequencies and longer durations of LIs.

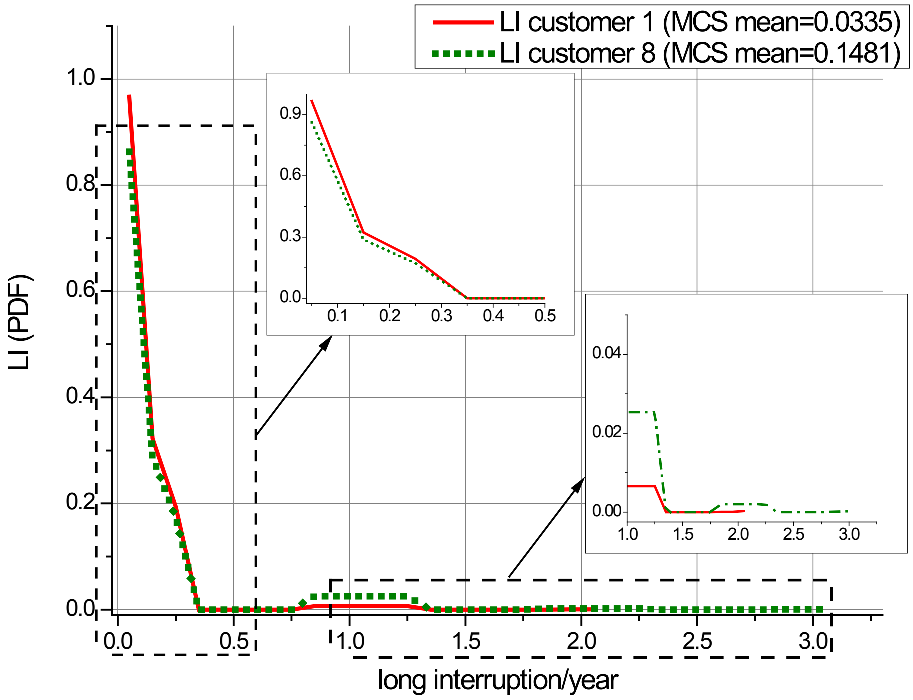


Figure 6.7: PDF for frequency of LIs for the best-served (Customer 1) and the worst-served (Customer 8) load points in generic urban MV network in Fig. 6.5.

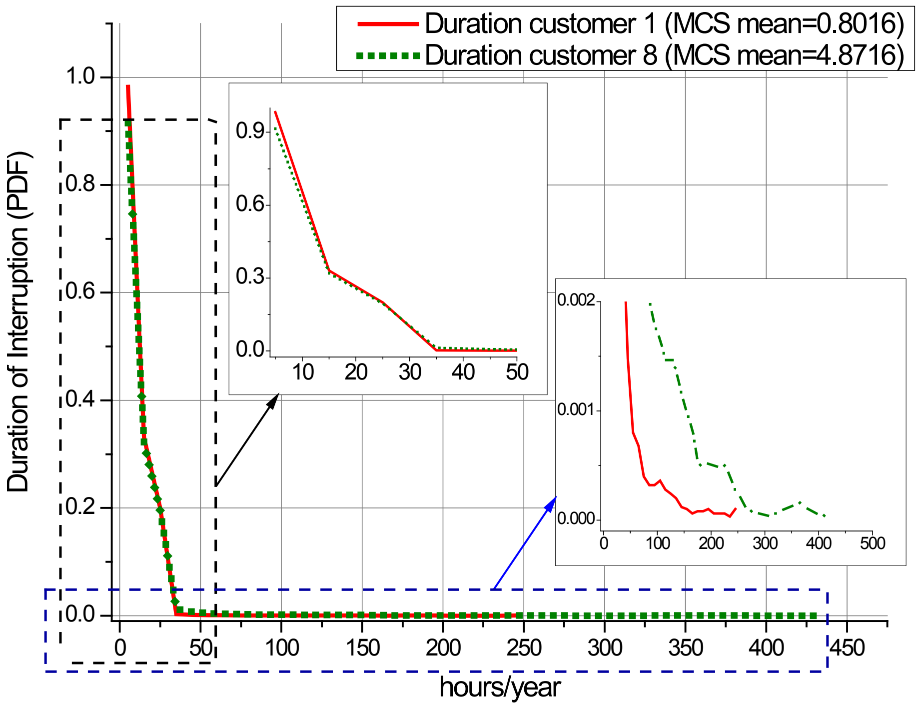


Figure 6.8: PDF for duration of LIs for the best-served (Customer 1) and the worst-served (Customer 8) load points in generic urban MV network in Fig. 6.5.

The results in Figs. 6.7 and 6.8 clearly show that the DG (and possible dedicated ES) located at the LV load point "Customer 8" (see Fig. 6.5) would be more beneficial than anywhere else in the considered generic MV network, as the reliability performance indicators are there 5-6 times worse than at LV load point "Customer 1". This will be particularly true if "islanded operation" is enabled at this load point, but even if this is not the case, the combined DG-ES system will help to reduce the loading of the network and network components, which is also location-based impact.

Further attempts are made to provide a more realistic analysis of the impact of DG on overall distribution network and customer reliability. Instead of using uniform fault rates and maximum load demand, the analysis presented next also includes load profiles (of residential customers) from Section 4.6.1, daily probabilities of fault rates, as discussed in Section 3.4.2 and DG power outputs [171]. With these inputs, different results will be obtained, as, for example, if one of the 33/11kV transformers in the primary distribution substation fails when the demand is lower than the power rating of the remaining 33/11kV transformer (i.e. 2/3 of the peak load), most, or even all of the customers might still be supplied (even after demand increase) if appropriate corrective action is taken by the DNOs (e.g. if they perform a prompt repair of the faulted transformer, before the demand increases over the rated power of the remaining transformer).

In this context, the coordination of the connected DG with a dedicated ES system could overcome problems with variable outputs of renewable DG and provide full support, as loads can be supplied from ES even if there is no RER (e.g. during the night in case of PV-based DG systems). Two different general schemes with ES are analysed: a) when the DG outputs are stored and used for reducing peak load demand (so called "peak load shaving application"), and b) when the DG outputs are stored and used for reducing demand during the hours of the day when the probability of fault/interruption is higher. The analysis is done for the DG penetration levels of:

20%, 30% and 50% of the peak demand and the three following cases besides the base Case 1 (no DG and no ES):

- Uncontrolled DG (Case 2) – daily DG outputs are estimated based on the variability of input RER and these outputs were injected into the grid (no energy storage is available).
- Energy Storage: Peak (Case 3) – daily DG outputs during the day are stored in the dedicated ES system and used (i.e. discharged into the grid) to reduce evening peak load (between 16:00-22:00 hours, Fig. 4.14).
- Energy Storage: Reliability (Case 4) – daily DG outputs during the day are stored in the dedicated ES system and used (i.e. discharged into the grid) during the hours of the day when there is a higher probability of fault (between 08:00-14:00 hours, Fig. 3.3) in order to reduce demand specifically for reliability improvement purposes.

With the above four cases, the benefits of using only DG (Case 2), using both DG and ES in a typical peak demand shaving applications (Case 3) and using both DG and ES in a specific reliability improvement application (Case 4) can be quantified in terms of the improvement in calculated reliability indices.

Table 6.13 shows the results of the corresponding MCS analysis, with fault rates and repair times modelled using the exponential distribution function [48, 49, 50] for the total duration of simulation period of 10,000 years.

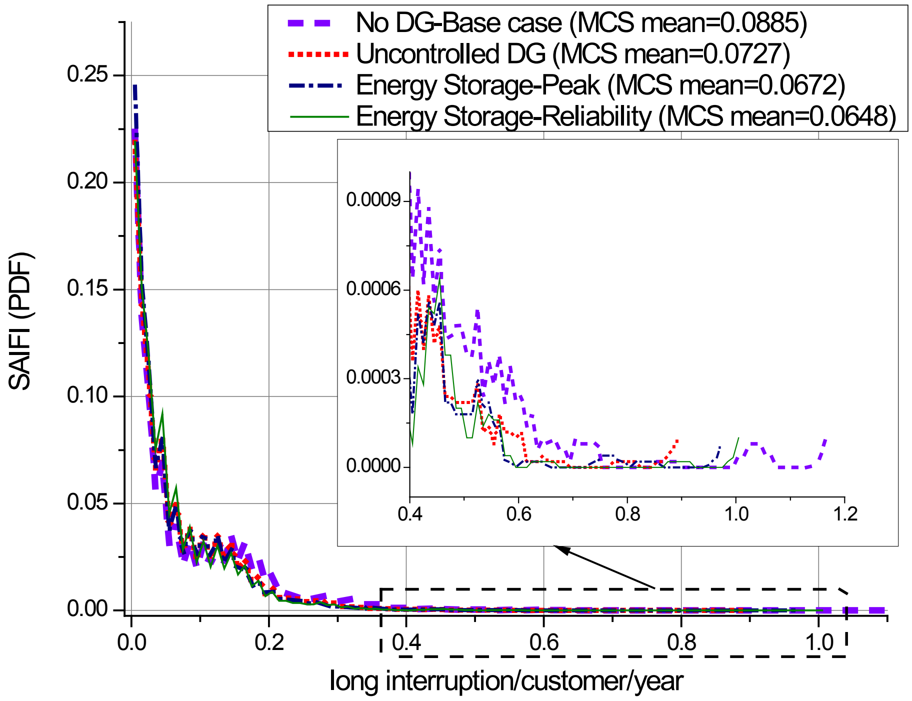
Table 6.13: Calculated Reliability Indices (mean values)

Case	DG %	SAIFI	MAIFI	SAIDI	CAIDI	ENS
1	0	0.0885	0.1120	2.7467	31.0374	3.8820
2	20	0.0727	0.0846	2.3079	28.5506	3.2619
	30	0.0621	0.0722	1.8808	27.8293	2.6583
	50	0.0491	0.0562	1.5019	26.7083	2.1228
3	20	0.0672	0.0780	2.1421	28.1420	3.0276
	30	0.0582	0.0673	1.8439	27.5183	2.6060
	50	0.0479	0.0555	1.3792	26.5919	1.9493
4	20	0.0648	0.0750	2.0723	28.0955	2.9289
	30	0.0562	0.0650	1.7460	27.4689	2.4677
	50	0.0383	0.0441	1.0655	25.7744	1.5059

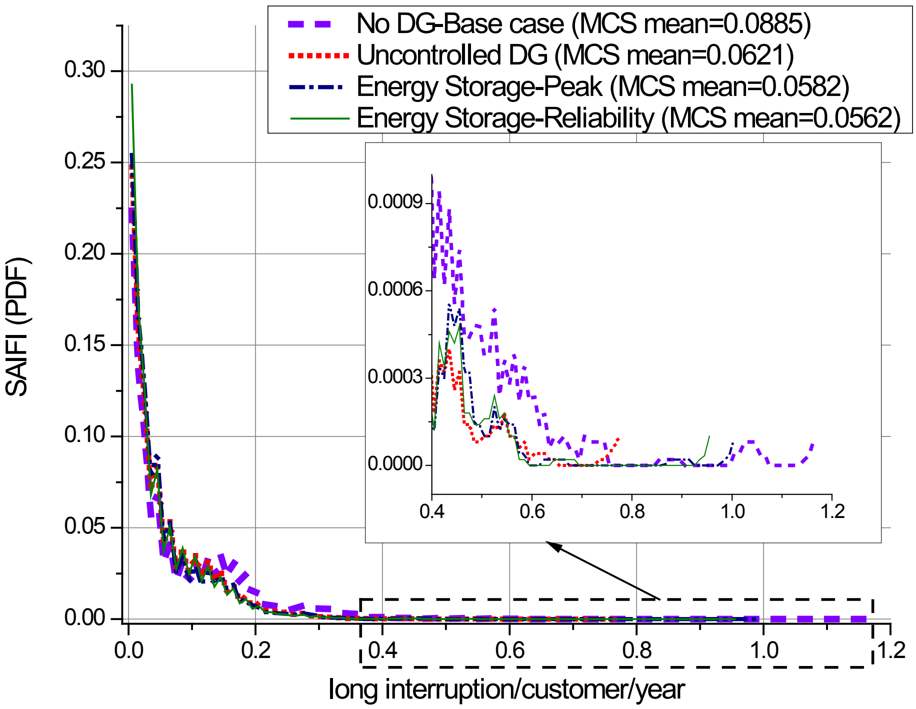
Based on the results in Table 6.13, it can be see that connection of DG helps to improve all reliability indices and that the improvement is stronger with the increased amount of DG connected. The main reason for this improvement is that the increasing DG penetration levels reduce the loading of the upstream network by locally supplying the neighbouring customers in the downstream network, which therefore do not depend on the supply from the grid. Therefore, the effects of the upstream network faults result in a reduced stress of the healthy part of the network and remaining network components, as they effectively supply the lower number of customers (e.g. one of the two 33/11kV transformers is now capable of supplying lower demand, i.e. only the portion of demand which is not supplied locally by DG and/or ES).

Different cases (Cases 2, 3 and 4) with the same DG penetration levels (20%, 30% and 50% of the peak demand) illustrate additional benefits of using ES and coordinating operation of combined DG-ES system with the actual network loading conditions (Case 3) and when the network is exposed to a higher probability of fault (Case 4). Among all considered cases, Case 4 emerges as the best scenario of implementing DG and ES in terms of reliability performance, giving an improvement of reliability indices of around 10%-20% in comparison with Case 3.

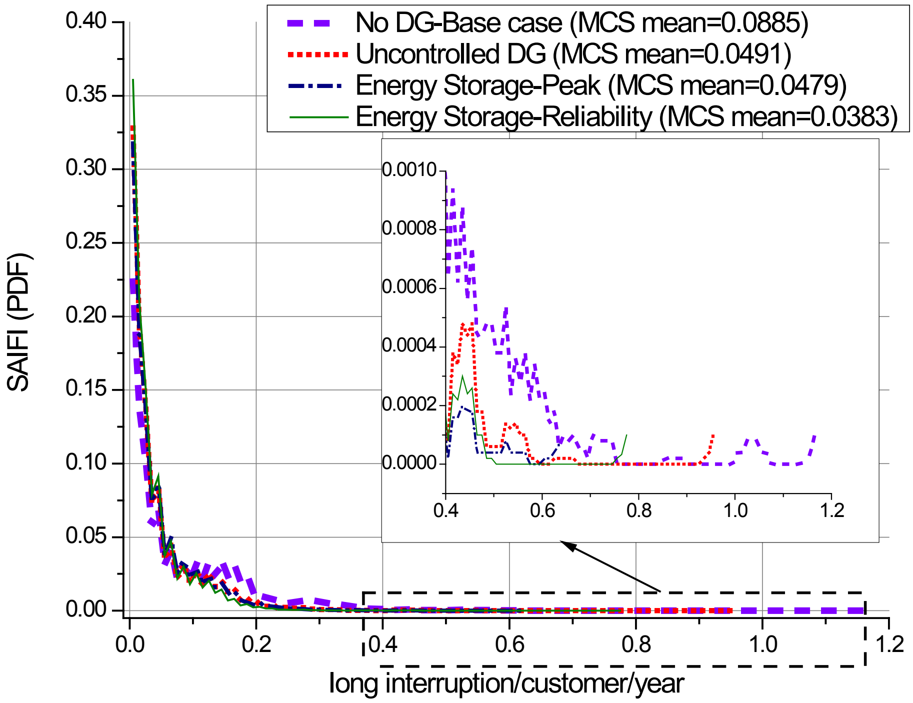
Figs. 6.9 and 6.10 presents PDFs for SAIFI and CAIDI reliability indices.



a) 20% DG penetration

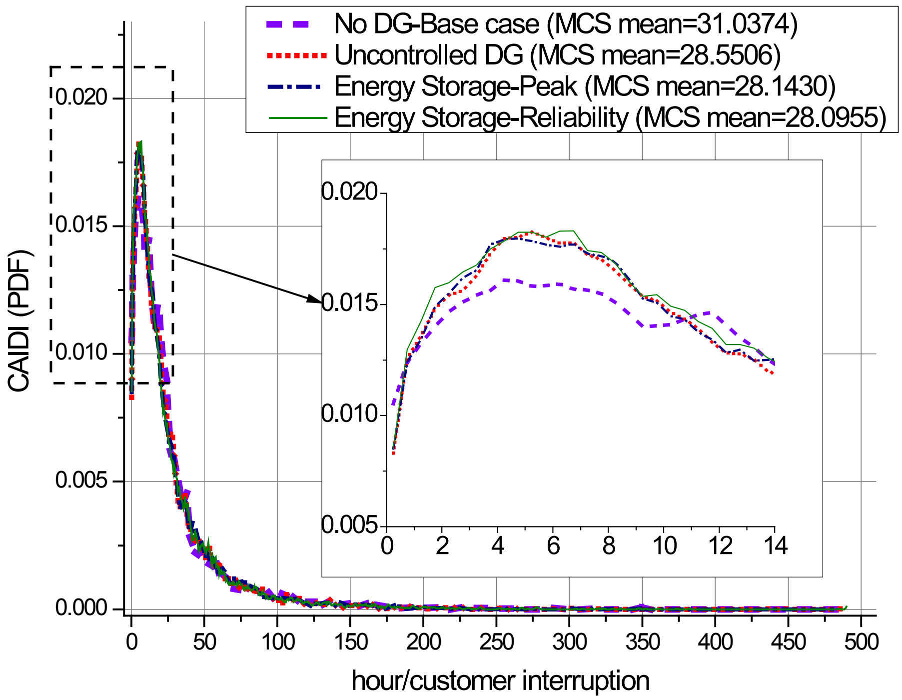


b) 30% DG penetration

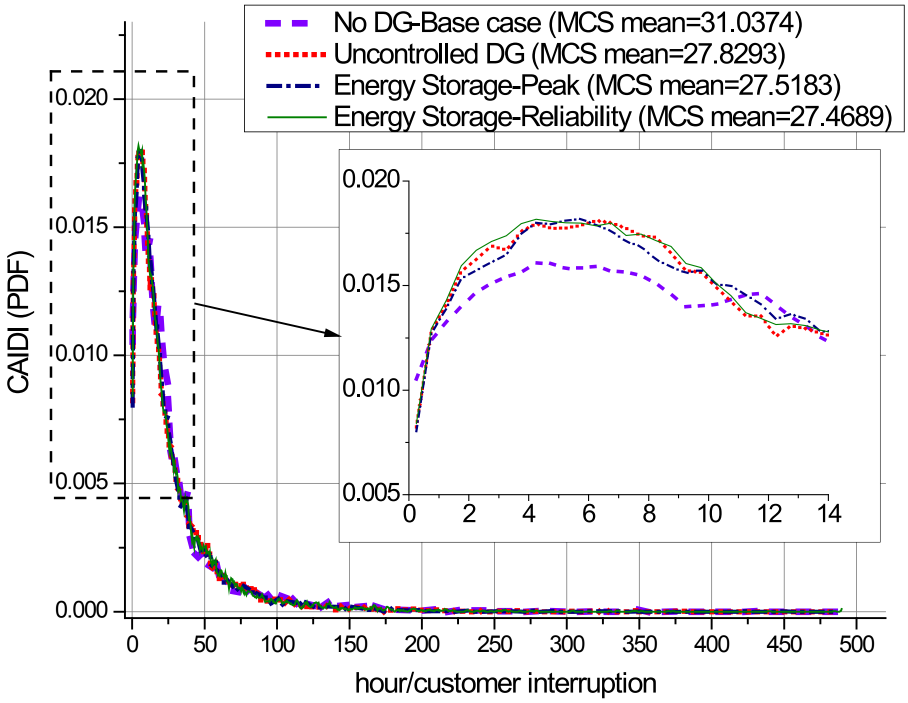


c) 50% DG penetration

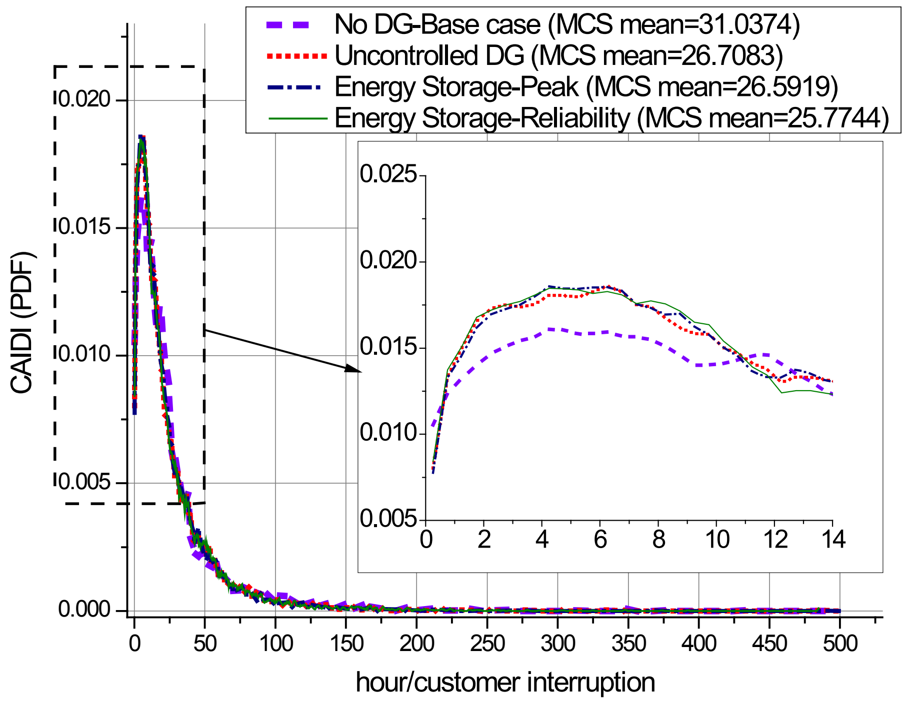
Figure 6.9: SAIFI index



a) 20% DG penetration



b) 30% DG penetration



c) 50% DG penetration

Figure 6.10: CAIDI index

Table 6.13 provides only results for mean values of reliability indices, while their distributions in Figs. 6.9 and 6.10 provide additional information. It can be seen in the zoomed-in parts of Fig. 6.9 that DG and ES increase the probability of zero LIs, based on the initial PDF values (for zero value on X-axis). Additionally, increased penetration levels of DG impact shorter 'tails' of the distribution curves, i.e. reduced probabilities of a high number of LIs (Fig. 6.9), as well as reduced probabilities of excessively long-duration LIs (Fig. 6.10). As previously discussed, situations in which more and more customers have their own generation capacity to supply their local demands (i.e. the increased DG penetration levels), effectively means that the energy not supplied due to the faults is not counted as ENS, as there is no interrupted customers (again, using example of two parallel transformers, one of them can supply all the loads in case of the fault of another transformer). This effect can be seen in Figure 6.10, where the PDF curves for 20%, 30% and 50% DG penetration levels are moving to the left, showing lower probabilities of CAIDI values.

Table 6.14 presents the results for the evaluation of DG benefits regarding the regulatory GSP requirements through the calculated risk of paying compensation. The risk reduces as the DG is incorporated within the network, thus suggesting that DG implementation will bring positive impact on DNOs (less penalty/compenasation payments) and improve reliability from customers' perspective (shorter duration of interruptions). The presented analysis did not consider the impact of possible reverse power flows on the calculated reliability indices.

Table 6.14: Penalty risks for 18 hours and 12 hours LI duration limits (in percentages)

Case	DG %	GSP limit	
		18 hours	12 hours
1	0	50.05	64.47
2	20	48.17	62.11
	30	47.82	61.93
	50	46.93	61.23
3	20	47.07	61.34
	30	46.97	61.61
	50	46.52	60.96
4	20	46.04	60.64
	30	45.94	60.48
	50	45.47	60.06

6.4 Chapter Summary

The implementation of SoS and GSP requirements during the assessment of the DNOs operational/reliability performance is important, as it is directly aimed at protecting supplied customers from excessively long and frequent long interruptions (there is currently no limits for frequency of SIs). Since Energy Regulators specify certain maximum duration of interruption limits for all customers, DNOs are able to calculate their risks of paying penalty/compensation based on their network performance. Through assessing these risks, the DNOs will be able to identify where upgrading and improving of their networks are required, through e.g. installation of new/additional protection equipment, or implementation of network automation and reconfiguration functionalities. This is even more important, as the Energy Regulators actively monitor and revise targets and limits imposed to the DNOs (for example, reduction of the maximum allowed duration of interruptions from 18 hours to 12 hours in the UK). The analysis in this chapter demonstrated how the risks of paying penalties and compensations can be evaluated and how specific “vulnerable” customer locations (where additional measures might be required) can be identified.

This chapter also presented analysis of the potential improvement of reliability performance after the implementation of DG with or without dedicated ES systems in LV distribution networks. The management and coordination of DG and ES with assumed loading conditions in the network is assessed in the time-sequential MCS calculation approach, allowing to specify and quantify benefits through the calculated reliability indices. In order to provide a more detailed analysis, two types of active DG integration and one type of passive DG integration are considered in this chapter. The passive DG integration is when DG is not managed and when no energy storage is implemented. The two type of active integration of DG with dedicated ES system are considered: a) one for "demand peak shaving" application (when DG outputs are stored during the day and discharged during the evening peak load), and b) another for "reliability improvement" (when DG outputs are stored during the evening and night, and then discharged during the morning and afternoon hours).

Chapter 7 Conclusions and Further Work

This thesis mainly focused on the formulation of improved methodologies for a more detailed and more confident assessment of reliability performance of MV and LV distribution networks. The basic approach was to consider and evaluate existing approaches and then identify points that can be improved, formulate these improvements and implement them in the comprehensive evaluation procedures and flexible models for the calculation of reliability indices. The various (typical) residential UK/Scottish MV and LV distribution networks were modelled with the four generic models, represented with detailed parameters, configurations, components, protection systems and typical operating and fault conditions. In general, most of the existing literature only present the general information on fault rates and repair times without distinguishing between different types of the networks and served customers. Therefore, a methodology was presented for segregating the fault rates and repair times for each of the four developed generic networks based on available statistics, data, DNO reports and further evaluations of network functionalities. Here, correct representation of LV networks is required to introduce a full three-phase model, in order to acknowledge relevant aspects of operation of real distribution networks and assess impact on customers. The analysis also includes SoS and GSP requirements, actual load profiles and daily probabilities of faults, which are used for the assessment of both system-average indices and network performance, but also for best-served and worst-served customers in considered networks. The analysis of variations and changes in network reliability performance is illustrated on a number of examples, including generic LV and MV network models, an offshore wind-based power plant and networks and several scenarios with different penetration levels of distributed generation with and without dedicated energy storage. The primary target "users" of the presented methodologies and models are DNOs, but the other parties and subjects (e.g. developers and supplied customers) could also use them for reliability assessment at both network planning and operation stages.

7.1 Reliability Assessment Methodologies

This thesis implemented two general approaches for analysing and quantifying reliability performance of all considered networks. The first approach relies on the use of analytical and deterministic methodology, which is based on the corresponding mathematical interpretations and calculations, and is still used in cases where the analysed networks are very complex and large, due to computational efficiency and simplicity. However, the analytical methods only provide a single set of output values for one set of input of parameters and network configurations, typically limited to the mean/average values of reliability indices. Additionally, the analytical methods are characterised with a limited ability to take into account differences in possible fault-response conditions, mainly due to the used protection systems, components and schemes, but also due to different types of faults. Some of the examples are operation of circuit breakers and sectionalisers (requiring first disconnection of the circuit breaker and then activation of the sectionaliser, which is strongly influenced by the actual location and type of fault), as well as possible different changes in network configurations, e.g. due to provision of alternative supply point with limited supply capabilities. Consequently, analytical methods provide limited information for the simplified network representation for restricted range of input of parameters.

The second used approach relied on the implementation of probabilistic methods, which in this thesis was Monte-Carlo simulation (MCS) method. The MCS approach allows to analyse network reliability performance taking into account time-sequence of events, providing a more comprehensive output results than just the mean value of reliability indices. However, the MCS approach also requires much longer computational times, which could be prohibitive in the case of very large and complex networks (or at least limited by the available computational resources). Since MCS-based analysis was inherently stochastic (there are no two identical MCS runs), it was required to define and implement certain accuracy and convergence criteria, which are in this thesis evaluated based on the coefficients of error and variation and requirements for the total simulation period based on the values of input data.

An important aspect of the analysis of modern power supply systems is an increased use of network automation, reconfiguration, remote control and alternative supply functionalities, which all essentially impact that faults which previously resulted in long supply interruptions (LIs) of customers are effectively resulting in short interruptions (SIs) of customers, therefore improving network reliability performance, but deteriorating power quality performance. This part of the analysis requires implement complex algorithms with careful evaluation of component repair times, network automation, reconfiguration, control and alternative supply transfer capabilities, but also types of implemented protection devices and their settings in analysing different types of faults (single, double and three-phase, which also can be permanent or transient). In this thesis, this was again done for all the four generic LV and MV network models.

7.2 Modelling of MV and LV Networks

In determining the typical network configurations and network components, as well as characteristics of supplied customers and applied protection systems, it is first essential to understand the main design criteria and operational principles of the considered networks. Within the specific network, every possible fault location is different both in terms of short circuit fault currents and, therefore, conditions to which protection devices (but also all other network components) will be exposed during the faults. This means that the same type of protection devices installed at different network locations will require different settings, while installation of different types of protection devices (e.g. fuses vs. circuit breakers) will require full re-evaluation of the analysis performed for one type of protection device in case of installation of other type(s). This is, perhaps, best illustrated in the thesis using the example of the LV networks, where it is shown that the standard single-line-diagram network representation (in most, if not all of conventional reliability assessment approaches) cannot be used due to the differences in operation of single-pole and three-pole protection devices and typical single-phase connection of residential customers in the UK.

The analysis in this thesis introduced a more detailed and, hopefully, more accurate classification of residential customers into four generic load subsectors, depending on the type of dwelling, location, size, geographical and circuit dispersion of demands. Accordingly, classification into four generic subsectors allowed to specify typical network configurations, components and protection systems supplying corresponding residential customers, generally denoted as highly-urban (HU), urban (U), sub-urban (SU) and rural (R) typical UK/Scottish LV and MV distribution networks. Each subsector is different in arrangement, configuration and types/sizes of components, as well as in operating conditions. In an urban/city area, where load density is high, customers are evenly distributed and loads are highly concentrated, shorter feeder lines in the form of underground cables are used due to limited space availability, better reliability performance and aesthetic reasons. In rural and sub-urban areas, however, dispersion of customers is higher, loads are non-evenly distributed and longer overhead line feeders are used, mainly due to reduced costs. Importantly, the overall exposure to faults and nature/type of experienced faults is different, which is, again, reflected in the different characteristics of supplying networks and applied protection systems. This required to provide full description and characterisation of the actual operating, protection, loading and fault conditions in the four generic LV and MV distribution network models, which was not available in the existing literature and previous work. Finally, this thesis also provides analysis of different sizes of the same-type generic networks, where ratings of the supplying primary and secondary distribution transformers are used as the main criteria for specifying number of served customers.

It is important to again highlight that the design, configuration and parameters of the networks and applied protection systems are different in MV and LV distribution networks, resulting in substantially different impact on reliability of supplied customers. For example, some of the differences that should be correctly analysed during the modelling of MV networks and LV networks are not only related to different voltage transformation (from 33kV to 11kV, or by the direct transformation of 132kV to 11kV in MV network, compared to 11kV to 0.4kV in LV networks), but also to redundancy and parallel network connection/operation of transformers in MV networks (full or partial N-1 security). Furthermore, most MV networks are designed with a meshed configuration, but operated in radial configuration due to available network reconfiguration capabilities and provision of alternative supply points.

An important contribution of this thesis is formulation of more detailed and more accurate reliability equivalent models of (generic) LV networks, specifically aimed at analysis of MV and HV networks, taking into account all abovementioned factors and parameters for the assessment of reliability performance. This allows to reduce computational times of MV/HV networks with the correct representation of LV network through the corresponding reliability equivalent models. This is illustrated using both analytical and probabilistic results for the calculated reliability indices and indicators (equivalent fault rates, SAIFI, equivalent repair times, CAIDI, etc.). DNOs or developers may use the generic LV and MV network models as base or reference models and cases for the reliability analysis, which may require further adjustment of network parameters and components, extension or reduction of network configuration, etc, based on the modelled geographical area, availability of generation/storage resources and load concentration.

7.3 Input Parameters for Reliability Assessment

Two basic input data for reliability assessment are mean fault rates and mean repair times (and their assumed or known distributions). These basic input parameters are in existing literature (and other sources, e.g. reports on network performance levels) almost always presented without the distinction between different network types and supplied areas. Therefore, this thesis presented a methodology for segregating fault rates and repair times into four considered generic residential load subsectors. This methodology starts from the analysis of available DNO reports and statistics, to evaluate coefficients for recalculating input data for the considered load subsector and incorporate them in the subsequent reliability assessment procedures.

Another important aspect (i.e. input data) of the presented reliability analysis is quantification of permanent and temporary faults for different generic LV and MV networks, as their proportions (and fault-response schemes) determine the numbers of LIs and SIs of supplied customers. Additionally, this analysis also took into account daily load curves of customers (which are typically represented by only the maximum demand in conventional approaches), and correlated these with daily fault probabilities, as determined after detailed analysis of fault statistics from the Scottish DNO. Again, the motivation was to reduce possible overestimations or underestimations of reliability performance indicators, i.e. to provide a more confident analysis of the possible ranges of variations of calculated output results.

7.4 Energy Regulator Requirements

In order to protect residential and small to medium size non-residential customers from excessively long and frequent supply interruptions, the Regulators usually define two main continuity of supplies requirements: guaranteed standard of performance, GSP, and security of supply, SoS. The GSP requirements are generally aimed at ensuring that every customer receives at least the minimum level of continuity of supply from the DNOs, e.g. specifying allowed limits for the maximum restoration time for up to 5,000 customers (12 hours) and more than 5,000 customers (24 hours), where the corresponding compensations are paid directly to the customers (not to the Regulator). The SoS requirements specify the maximum times for restoring supply to at least a minimum group demands of the interrupted customers, classified in six groups/classes, again based on the amount of interruptes demands (i.e. number of customers). This thesis not only incorporates these requirements in the analysis (e.g. by re-evaluating some of the reported mean fault rates and, particularly, mean repair times for the assessment of LIs), but also proposes a methodology for calculating risks of paying penalty or compensation for various scenarios with the considered generic LV and MV networks.

7.5 Evaluation of Average, Best and Worst Served Customers

DNOs usually report SAIFI (or CI), MAIFI (or SI), SAIDI (or CML), CAIDI and few other reliability indices expressing performance of an "average customer", as these indices are calculated as single average (mean) values taking into account all served customers in a given network. From a system-based point of view, these values are sufficient for representing and reporting the DNOs' network performance. However, the corresponding "average customer" is generally fictitious, as the actual supplied customers will have both better and worse performance. Accordingly, this thesis presented analysis in which best-served and worst-served actual customers are identified for the considered generic LV and MV networks (in terms of both the numbers of interruptions and durations of interruptions) and for which risks of penalty/compensation are calculated.

7.6 Integration of DG and ES

The analysis presented in this PhD thesis considered some aspects of the operation of modern electricity networks which are generally denoted as "smart grid" functionalities, e.g. increased reconfiguration flexibility, automation, remote control and provision of alternative supply. Particular attention is given to the analysis of increasing penetration levels of variable renewable-based distributed generation (DG) technologies, with or without dedicated energy storage (ES) systems. This part of the analysis showed that DG and ES, especially when coordinated, might have strong impact on system reliability performance, even if they do not allow operation in the "islanded mode".

Several considered scenarios for management and coordinated control of DG and ES are quantified in terms of the calculated reliability indices for the considered LV generic networks, showing that the best location for DG and ES is at the points where the total duration of supply interruptions is the longest/worst. This analysis implemented the MCS approach, allowing to implement time-varying daily fault rates and estimate when exactly outputs of DG should be stored and when stored energy should be discharged. Accordingly, it is shown that the most beneficial impact of DG and ES would be when demands are reduced during the times of the day when the probability of fault is high.

7.7 Research Limitations

The main limitations of the research, analysis and methodologies presented in this thesis can be summarised as follows.

1. Implementation of MCS-based approaches results in inherently stochastic output results, requiring to define (and evaluate) both accuracy requirements and sufficient duration of the total simulation period. As previously discussed, the MCS approaches require longer simulation times than the analytical approaches. The simulation times can be reduced by increasing the time step of the simulation, which in this thesis was selected as 15 or 30 minutes. However, a 1-minute time-step (or better) is required for simulations to provide fully confident discrimination of LIs from SIs, while for a short circuit analysis time-step of one second (or better) is required to make clear distinction between permanent, temporary, transient, developing and intermittent faults. For example, an attempt was made to increase the accuracy by reducing the time-step of simulation in this thesis, using one minute and even one second step, but it was found that will require months of simulations with a massive sets of output simulation data, requiring prohibitively high computational and data-processing resources. Therefore, the best trade-off option between accuracy and simulation times was found when the time simulation steps between 15 and 30 minutes are used (if there was an interruption within one time-step, it was considered to be SI, while an interruption in more than one successive simulation time-steps was considered to be LI). Comparison of mean values with the analytical methods confirmed that relatively large time-steps used in this thesis did not affect much the accuracy of the calculated reliability indices results.

2. Accurate/Confident calculation of reliability indices requires comprehensive and detailed input data, which strongly depend on the available information from past statistics and historical records of fault rates and repair times of network components. As discussed in the thesis, available literature and reports do not provide complete or at least sufficient information, which generally should distinguish between different voltage levels, types of the networks, sizes and types of the components and other relevant factors (e.g. age of components in operation). For example, various sources for mean fault rates of DG did not provide information on exact voltage levels, but only general indication of HV, MV and LV, while DNOs generally do not provide information on SAIFI and MAIFI indices separately for MV or LV level, but only on “distribution networks”, which consists of both MV and LV parts. Consequently, this thesis used the same proportions of SI and LI in both MV and LV networks, which is generally not the case in the real networks.
3. The modelling of MV and LV networks with detailed configurations, parameters and types/sizes/settings of network components required the specification of significant amount of information. Although there were some sources for specifying required input data, most of them do not divide general distribution networks into (highly) urban, rural or sub-urban types/areas. Therefore, some of the network models are changed/adjusted, in order to correctly represent the changes in the networks supplying different customers at different locations. For example, the LV urban network configuration was available from [39], but no (clear and detailed) information was available for the configuration of LV highly-urban network, which was in this thesis developed as a logical and technical extension of urban network. Statistically, the populations and numbers of customers in highly-urban areas/networks are higher than in urban areas/networks, and similar configurations and principles of operations are applied with increased numbers of service connection feeders in highly-urban areas and a few other modifications (e.g. use of direct transformation).

4. The output of the calculated reliability analysis should be validated in some suitable ways (e.g. by comparing calculated and reported indices in case of modelling actual networks), but this generally require a large number of measurements performed on specific areas of distribution networks. Since the generic networks analysed, modelled and simulated in this thesis are relatively small and it was not clear how available information on system reliability performance can be applied to these networks, it can be generally concluded that the validation of generic HU/U/SU/R LV and MV networks and corresponding network models (including reliability equivalents) was not as robust and as detailed as would be desirable. This was done to the extent which was possible within the available time for this research, with, for example, validation of the specific stages of the modelling process, in order to provide confidence in the final results. For this purpose, another reliability indicator based on load sector [152] can be used to evaluate the trends in fault rates and repair times. This information was considered sufficient for the validation, as the analysed generic networks followed the past performance trends in different load subsectors.

7.8 Recommendations for Further Work

Some aspects of the presented methodologies, modelling approaches and simulation/calculation procedures could be further improved (or updated), including:

1. Within the presented MCS approaches, the same load profiles are used for all four residential load sub-sectors, assuming that changes between them are not large. However, demands and load profiles are different in different load sectors, and estimated reliability performance will be improved if simulations include more than one load profile. Furthermore, this thesis correlated daily probability fault rates with the daily load profiles, where an average daily probability fault rate is used to model occurrence of faults in all load subsectors. However, different networks with different network components will ultimately result in different daily probability fault rates, e.g. depending

on the electrical insulation/stress levels, exposure to elements and external factors. etc. Therefore, it is expected that further improvements could be achieved if more detailed daily load profiles and daily fault probabilities are combined in the presented MCS approaches. Although statistical reliability data and databases by DNOs generally allow to extract information on faults and repair times of HU, U, SU and R networks (e.g. by suitable querying of databases), which will then directly validate some of the presented results, accessing these data was not possible during this PhD research.

2. The LV distribution network models were presented with detailed configurations and parameters, which is unprecedented in existing literature on reliability performance assessment. Although most of the network models are in this thesis developed and presented as the “complete models”, at least in terms of their implementation for reliability analysis, LV networks are simulated as typical UK single-phase residential networks, where protection and control are based on single-pole components. For example, in the case of a single-phase fault in LV networks, only one phase was affected, while the other two phases were “healthy” and still receiving continuous power supply. However, most of the customers in Europe are three-phase connected and, for a comparable analysis, the presented methodology should be modified to allow for the implementation of the three-pole protection and control equipment in the modelling of generic LV distribution networks.
3. Finally, the next step of the work could concentrate on obtaining output results with the higher resolution. This is already discussed as one of the limitations of the presented research, where the MCS approach could be simulated with a shorter time-step, in order to not increase the accuracy of the results in terms of more confident evaluation of LIs and SIs. The higher computational requirements for shorter simulation time-steps could be resolved if parallel high-speed computing resources are used in suitably formulated algorithms, which was out of the scope of this thesis, but is another possible direction of further research.

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Appendix A: Matlab code for Monte-Carlo Simulation

```
%-------------------------------------------------------------------
% Variables to define:
% size of components

pc_start=1;
pc_end=3;

folder=1;
dir=['/home/s1263089/Documents/'];
cd(dir);

% load fault rates and repair times of array of components
load lambda_LVHU_case4
load miu_LVHU_case4

% most components percentage of SI and LI ratio
li=1; %in per unit
si=1-li;

pc_size=(pc_end-pc_start)+1;

li_seq=zeros(1,pc_size);
si_seq=zeros(1,pc_size);
for h=1:pc_size
    li_seq(h)=li;
    si_seq(h)=si;
end


%-------------------------------------------------------------------
% if there any irregular ratio of SI and LI from most components
li_r=0; % in per unit
si_r=1-li_r;

pc_irregular=[1 2]; % irregular no of power component sequence

size_irregular=numel(pc_irregular);
for q=1:size_irregular
    r=pc_irregular(q);

    li_seq(r)=li_r;
    si_seq(r)=si_r;
end


%-------------------------------------------------------------------
% define numbers of simulation
lambda1=lambda_LVHU_case4(1,pc_start:pc_end);
miu=miu_LVHU_case4(1,pc_start:pc_end);
```

```
years=10000;    % number of years of simulation
multiplier=1; % down to days scale
step=1;  % no of steps in one hour
hours=1*step;   % 24 hours times with 2 step = 48 step of 30 minutes
days=years*multiplier*hours;

lambda=lambda1/(multiplier*hours);   % failure/hours
miu=miu*step;   % in hours steps


%--------------------------------------------
% fault rates daily probabilities
lambda_probabilities=zeros(hours,1);
lambda2=1;
for o=1:hours; % probabilities of fault rates in one day
    if (o>=1 && o<=(5*step));
        lambda_probabilities(o,:)=lambda2*0.375;

    elseif (o>(5*step) && o<=(10*step));
        lambda_probabilities(o,:)=lambda2*((0.225*((o/step)-1))-
0.525);

    elseif (o>(10*step) && o<=(18*step));
        lambda_probabilities(o,:)=lambda2*1.5;

    elseif (o>(18*step) && o<=(24*step));
        lambda_probabilities(o,:)=lambda2*((237/56)-
((9/56)*((o/step)-1)));

    end

end

p=1;
q=hours;
for j=1:multiplier*years;
    lambda_1(p+j-1:q+j-1,1)=lambda_probabilities; % fault rates
extend in days*years

    p=p+hours-1;
    q=q+hours-1;
end


%-------------------------------------------------------------------
%accuracy define up to 10,000 years
u_lambda_accuracy=zeros(1,length(lambda));
l_lambda_accuracy=zeros(1,length(lambda));
u_miu_accuracy=zeros(1,length(lambda));
l_miu_accuracy=zeros(1,length(lambda));
for i=1:length(lambda)
    if (lambda1(i)>=0.1)    %lambda 2% miu 2%
        u_lambda_accuracy(i)=1.02;
        l_lambda_accuracy(i)=0.98;
        u_miu_accuracy(i)=1.02;
        l_miu_accuracy(i)=0.98;
```

```
    elseif (lambda1(i)>=0.01 && lambda1(i)<0.1)  %lambda 5% miu 3%
        u_lambda_accuracy(i)=1.05;
        l_lambda_accuracy(i)=0.95;
        u_miu_accuracy(i)=1.02;
        l_miu_accuracy(i)=0.98;

    elseif (lambda1(i)>=0.001 && lambda1(i)<0.01) %lambda 10% miu 5%
        u_lambda_accuracy(i)=1.1;
        l_lambda_accuracy(i)=0.9;
        u_miu_accuracy(i)=1.05;
        l_miu_accuracy(i)=0.95;

    elseif (lambda1(i)>=0.0002 && lambda1(i)<0.001) %lambda 20% miu
5%
        u_lambda_accuracy(i)=1.2;
        l_lambda_accuracy(i)=0.8;
        u_miu_accuracy(i)=1.05;
        l_miu_accuracy(i)=0.95;

    elseif (lambda1(i)<0.0002)  %lambda & miu 100%
        u_lambda_accuracy(i)=2;
        l_lambda_accuracy(i)=0;
        u_miu_accuracy(i)=2;
        l_miu_accuracy(i)=0;

    else
    end
end

% lambda accuracy
upper_lambda=lambda1.*u_lambda_accuracy;
lower_lambda=lambda1.*l_lambda_accuracy;

% miu accuracy
upper_miu=miu.*u_miu_accuracy;
lower_miu=miu.*l_miu_accuracy;


%------------------------------------------------------------------
% inverse transformation of TTF (fault rates)
TTF=zeros(days,length(lambda));

%Weibull Distribution Family
b3=1;   % EXPONENTIAL Distribution: b=1
G3=miu/(gamma(1+(1/b3)));

A3=zeros(1,length(lambda));
for z=1:length(lambda)
    U1=rand(days,1);
    for k=1:days
        TTF(k,z)=(-1/(lambda_1*lambda(z)))*log(U1(k,1));  % Inverse
Exponential CDF for Fault Rates
    end
    TTF=round(TTF);
    A1=find(TTF(:,z)==1);
```

```
    A2=length(A1)/years;

    % check and re-calculate if output not within accuracy limit
    while (A2<=lower_lambda(z) || A2>=upper_lambda(z));
        U1=rand(days,1);
        for k=1:days
            TTF(k,z)=(-1/(lambda_1*lambda(z)))*log(U1(k,1));  %
Inverse Exponential CDF for Fault Rates
        end
        TTF=round(TTF);
        A1=find(TTF(:,z)==1);
        A2=length(A1)/years;

        if (A2>=lower_lambda(z) && A2<=upper_lambda(z));
            break
        end

    end
    A3(1,z)=A2;
end


%--------------------------------------------------------------------
% for checking purposed of fault rates
B=zeros(1,length(lambda));
F=zeros(1,length(lambda));
for j=1:length(lambda);
    A=find(TTF(:,j)==1); % find the number of occurance of fault for
each power component
    B(1,j)=length(A);   % array of number of occurance of fault for
each power component
    F(1,j)=length(A)/years; % mean of lambda after
exponential/raleigh distribution (before 46percent)
end


%--------------------------------------------------------------------
 B2=zeros(1,pc_size);
upper_B2=zeros(1,pc_size);
lower_B2=zeros(1,pc_size);
for p=1:pc_size
    B2(p)=B(p)*li_seq(p);

    upper_B2(p)=B2(p)*u_lambda_accuracy(p)*1.1;
    lower_B2(p)=B2(p)*l_lambda_accuracy(p)*0.9;
end


%--------------------------------------------------------------------
% separate LI and SI of fault rates based on previous ratio
C=max(B);
f_LI_1=zeros(C,length(lambda));
f_SI_1=zeros(C,length(lambda));
TTR1=zeros(C,length(lambda));
mean_TTR_2=zeros(1,length(lambda));
for l=1:length(lambda);
```

```
     SI_LI=randsrc(B(1,l),1,[0 2;si_seq(l) li_seq(l)]);% 0=SI,2=LI
     LI=find(SI_LI);
     SI=find(SI_LI<2);

     G=find(TTF(:,l)==1);
     f_LI=G(LI); % location of fault for LI
     D=length(f_LI);

    % check accuracy of LI/SI ratio
    while (D<=lower_B2(l) || D>=upper_B2(l));
        SI_LI=randsrc(B(1,l),1,[0 2;si_seq(l) li_seq(l)]);%0=SI,2=LI
        LI=find(SI_LI);
        SI=find(SI_LI<2);

        G=find(TTF(:,l)==1);
        f_LI=G(LI); % location of fault for LI
        D=length(f_LI);

        if (D>=lower_B2(l) && D<=upper_B2(l));
            break
        end
    end

    f_SI=G(SI); % location of fault for SI
    E=length(f_SI);

    f_LI_1(1:D,l)=f_LI;
    f_SI_1(1:E,l)=f_SI;

    % inverse transformation of TTR (mean time to repair)
    U2=rand(D,1);
    TTR=zeros(C,1);
    for m=1:D;
        TTR(m,1)=G3(l)*(-log(U2(m)))^(1/b3);     % Inverse Weibull
(Exponential) CDF for each power component depending on how many
interruption per power component in order to get mean values for
each power component
    end

    B1=find(TTR>0);
    mean_TTR=mean(TTR(B1));

    % check and re-calculate if output not within accuracy limit
    while (mean_TTR<=lower_miu(l) || mean_TTR>=upper_miu(l));
        U2=rand(D,1);
        for m=1:D;
            TTR(m,1)=G3(l)*(-log(U2(m)))^(1/b3);     % Inverse
Weibull (Exponential) CDF for each power component depending on how
many interruption per power component in order to get mean values
for each power component
        end

        B1=find(TTR>0);
        mean_TTR=mean(TTR(B1));
```

```
        if (mean_TTR>=lower_miu(l) && mean_TTR<=upper_miu(l));
            break
        end

    end

    mean_TTR_2(1,l)=mean_TTR;    % to check mean MTTR
    TTR1(:,l)=TTR;   % distribution of MTTR
end


%-------------------------------------------------------------------
% find the location of LI
c=0;
f_LI_2=zeros(C,length(lambda));
for a=1:length(lambda);
    for b=1:C;
        if (f_LI_1(b,a)>0);
            f_LI_2(b,a)=f_LI_1(b,a)+(days*c);
        else
            f_LI_2(b,a)=f_LI_1(b,a);
        end
    end
    c=c+1;
end

% find the location of SI
d=0;
f_SI_2=zeros(C,length(lambda));
for e=1:length(lambda);
    for g=1:C;
        if (f_SI_1(g,e)>0);
            f_SI_2(g,e)=f_SI_1(g,e)+(days*d);
        else
            f_SI_2(g,e)=f_SI_1(g,e);
        end
    end
    d=d+1;
end


%-------------------------------------------------------------------
% for checking the mean values of fault rates and MTTR for every
components
mean_lambda_46=zeros(1,length(lambda));
mean_TTR2=zeros(1,length(lambda));
for n=1:length(lambda);
    f1=find(TTR1(:,n)>0);
    mean_lambda_46(:,n)=length(f1)/years;    %mean of lambda after LI
ratio

    TTR2=TTR1(f1,n);
    mean_TTR2(:,n)=mean(TTR2);  %mean of MTTR after
exponential/raleigh distribution
end

mean_si=zeros(1,length(lambda));
```

```
for zz=1:length(lambda);
    f1_12=find(f_SI_2(:,zz)>0);
    mean_si(:,zz)=length(f1_12)/years;    %mean of lambda after LI
ratio

end


%-------------------------------------------------------------------
% for input of simulation
f2=find(TTR1>0);
TTR3=TTR1(f2);  %final value of LI without rounding
TTR4=round(TTR3);   %final value of LI with rounding

f3=find(f_LI_2>0);
f_li=f_LI_2(f3);    %final location of LI

f4=find(f_SI_2>0);
f_si=f_SI_2(f4);    %final location of SI

dir2=[dir '/' int2str(folder)];
cd(dir2)

save -v7.3 f_li f_li
save -v7.3 f_si f_si
save -v7.3 TTR4 TTR4

save -v7.3 pc_start pc_start
save -v7.3 pc_end pc_end
save -v7.3 pc_size pc_size
save -v7.3 years years
save -v7.3 multiplier multiplier
save -v7.3 hours hours
save -v7.3 dir dir
```

Appendix B: Python code for PSS/E Simulation

```
# read load profile data
h=open(r"""C:\Users\Mohd Ikhwan\Desktop\urban\simulation\analytical\lp_avg.txt""", 'r')
i = 0
while i < 1:
    temp=float(h.readline())
    LOAD.extend([temp])
    i = i + 1
h.close()


# read power factor data
PF=[]
h=open(r"""C:\Users\Mohd Ikhwan\Desktop\urban\simulation\analytical\pf_avg.txt""", 'r')
i = 0
while i < 1:
    temp = float(h.readline())
    PF.extend([temp])
    i = i + 1
h.close()


# start point of simulation
import os

p=1
while p < 10001:

    path1="S:/Documents/LVHU3phasefuseCB_v2/Input_text/%d" %(p)

    os.chdir(path1)



    psspy.case(r"""S:\Documents\LVHU3phasefuseCB_v2\ignacio\LVHU3phaseCB.sav""")

    # suppress outputs in the PSSE display
    psspy.report_output(6,"",[0,0])
    psspy.progress_output(6,"",[0,0])
    psspy.alert_output(6,"",[0,0])

    # initialise load status arrays (0=interrupted / not 0 = normal operation)
    l_1=[]
    l_2=[]
    l_3=[]
    l_4=[]
    l_5=[]
    l_6=[]
    l_7=[]
    l_8=[]
    l_9=[]
    l_10=[]
    l_11=[]
    l_12=[]
    l_13=[]
    l_14=[]
    l_15=[]
    l_16=[]
    l_17=[]
    l_18=[]
    l_19=[]


    # read 17520 x 30min status (0-open or 1-closed) coefficients
    NPCs=545 # declare number of power components     (+ 2 Backups =146 PCs)
    PC=[0]*NPCs #declare empty array of loads

    npc=0
```

```
while npc<NPCs:

    PCtemp=[]
    exec "f=open('PC%d.txt', "r")" % (npc+1)
    i = 0
    while i < 2880:                ### 17520 steps (1year in 30min)
        temp=float(f.readline())
        PCtemp.extend([temp])
        i = i + 1
    f.close()
    PC[npc]=PCtemp
    npc=npc+1


N=0

while N<2880:

    psspy.case(r"""S:\Documents\LVHU3phasefuseCB_v2\ignacio\LVHU3phaseCB.sav""")

#------------------------------------------------------------------------------
# Create subsystem with 19 loads (Residential)

psspy.bsys(2,0,[0.0,0.0],0,[],19,[1016,1017,1023,1032,2012,2022,3013,3026,3027,3029,3034,3035,3049,30410,30411,3053,30
63,4015,4016],0,[],0,[]) #buses IDs


# Change Load Profile
# Residential
    psspy.scal(2,0,1,[0,0,0,0],[0.0,0.0,0.0,0.0,0.0,0.0,0.0])
    psspy.scal(2,0,2,[2,0,1,0],[LOAD[N],0.0,0.0,0.0,0.0,0.0,0.0])


# change PF
# Residential
    psspy.scal(2,0,1,[0,0,0,0],[0.0,0.0,0.0,0.0,0.0,0.0,0.0])
    psspy.scal(2,0,2,[2,0,4,0],[ 0.0,0.0,0.0,0.0,0.0,0.0,PF[N]])


#------------------------------------------------------------------------------
# Change status (on/off) for all Power Components:
# cable 0.2kV
    if PC[0][N]==0: psspy.branch_chng(7,201,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[1][N]==0: psspy.branch_chng(7,202,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[2][N]==0: psspy.branch_chng(7,203,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[3][N]==0: psspy.branch_chng(7,204,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[4][N]==0: psspy.branch_chng(7,205,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[5][N]==0: psspy.branch_chng(7,206,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[6][N]==0: psspy.branch_chng(7,207,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

    if PC[7][N]==0: psspy.branch_chng(9,208,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[8][N]==0: psspy.branch_chng(9,209,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[9][N]==0: psspy.branch_chng(9,210,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[10][N]==0: psspy.branch_chng(9,211,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[11][N]==0: psspy.branch_chng(9,212,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[12][N]==0: psspy.branch_chng(9,213,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[13][N]==0: psspy.branch_chng(9,214,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


# fuse 0.4kV
    if PC[380][N]==0: psspy.branch_chng(5,6,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[381][N]==0: psspy.branch_chng(5,8,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[382][N]==0: psspy.branch_chng(10,11,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[383][N]==0: psspy.branch_chng(10,13,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

    if PC[384][N]==0: psspy.branch_chng(55,56,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[385][N]==0: psspy.branch_chng(58,59,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[386][N]==0: psspy.branch_chng(60,61,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[387][N]==0: psspy.branch_chng(60,63,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[388][N]==0: psspy.branch_chng(65,66,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[389][N]==0: psspy.branch_chng(65,67,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
    if PC[390][N]==0: psspy.branch_chng(70,71,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
```

```
        if PC[391][N]==0: psspy.branch_chng(73,74,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[392][N]==0: psspy.branch_chng(73,76,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[393][N]==0: psspy.branch_chng(78,79,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[394][N]==0: psspy.branch_chng(78,81,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


    # circuit breaker 0.4kV
        if PC[428][N]==0: psspy.branch_chng(2,3,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        if PC[429][N]==0: psspy.branch_chng(2,39,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[430][N]==0: psspy.branch_chng(40,41,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[431][N]==0: psspy.branch_chng(40,42,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        if PC[432][N]==0: psspy.branch_chng(2,54,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


    # cable 0.4kV
        if PC[449][N]==0: psspy.branch_chng(3,4,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[450][N]==0: psspy.branch_chng(4,5,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[451][N]==0: psspy.branch_chng(6,7,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[452][N]==0: psspy.branch_chng(8,9,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[453][N]==0: psspy.branch_chng(10,162,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[454][N]==0: psspy.branch_chng(11,12,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[455][N]==0: psspy.branch_chng(13,14,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        if PC[456][N]==0: psspy.branch_chng(39,40,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[457][N]==0: psspy.branch_chng(42,43,r"""1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


    #Additional circuit breaker 0.4KV
        if PC[539][N]==0: psspy.branch_chng(4,162,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[540][N]==0: psspy.branch_chng(16,163,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[541][N]==0: psspy.branch_chng(28,164,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        if PC[542][N]==0: psspy.branch_chng(65,165,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[543][N]==0: psspy.branch_chng(95,166,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])
        if PC[544][N]==0: psspy.branch_chng(125,167,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


    # Additional function of circuit breaker that trip another component that within it's control
    # cb 2-3
        if PC[449][N]==0 or PC[450][N]==0:
psspy.branch_chng(2,3,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

    # cb 4-162
        if PC[453][N]==0: psspy.branch_chng(4,162,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


    # cb 2-15
        if PC[479][N]==0 or PC[480][N]==0:
psspy.branch_chng(2,15,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

    # cb 16-163
        if PC[483][N]==0: psspy.branch_chng(16,163,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


    # cb 2-27
        if PC[509][N]==0 or PC[510][N]==0:
psspy.branch_chng(2,27,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

    # cb 28-164
        if PC[513][N]==0: psspy.branch_chng(28,164,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


    # cb 2-54
        if PC[458][N]==0 or PC[460][N]==0 or PC[461][N]==0 or PC[464][N]==0:
psspy.branch_chng(2,54,r"""@1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

    # cb 65-165

    # Additional function of fuse that trip another component that within it's control
    # fuse 5-6
```

```
            if PC[0][N]==0 or PC[1][N]==0 or PC[2][N]==0 or PC[3][N]==0 or PC[4][N]==0 or PC[5][N]==0 or PC[6][N]==0:
psspy.branch_chng(5,6,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        # fuse 5-8
            if PC[7][N]==0 or PC[8][N]==0 or PC[9][N]==0 or PC[10][N]==0 or PC[11][N]==0 or PC[12][N]==0 or
PC[13][N]==0: psspy.branch_chng(5,8,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        # fuse 10-11
            if PC[14][N]==0 or PC[15][N]==0 or PC[16][N]==0 or PC[17][N]==0 or PC[18][N]==0 or PC[19][N]==0:
psspy.branch_chng(10,11,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        # fuse 10-13
            if PC[20][N]==0 or PC[21][N]==0 or PC[22][N]==0 or PC[23][N]==0 or PC[24][N]==0 or PC[25][N]==0:
psspy.branch_chng(10,13,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])

        # fuse 17-18
            if PC[26][N]==0 or PC[27][N]==0 or PC[28][N]==0 or PC[29][N]==0 or PC[30][N]==0 or PC[31][N]==0 or
PC[32][N]==0: psspy.branch_chng(17,18,r"""*1""",[0,_i,_i,_i,_i,_i],[_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f,_f])


# Check for Bus Islands - component which is not connected with swing bus
            psspy.tree(1,0)
            psspy.tree(2,1)
            psspy.tree(2,1)
            psspy.tree(2,1)
            psspy.tree(2,1)
            psspy.tree(2,1)

# Solve Newton-Raphson
            psspy.fdns([1,0,0,1,1,0,99,0])

# Get Output Files
            ierr,l1=psspy.brnmsc(7,201,'1','PCTCPA')
            l_1.extend([l1])
            ierr,l2=psspy.brnmsc(9,208,'1','PCTCPA')
            l_2.extend([l2])
            ierr,l3=psspy.brnmsc(12,215,'1','PCTCPA')
            l_3.extend([l3])
            ierr,l4=psspy.brnmsc(14,221,'1','PCTCPA')
            l_4.extend([l4])
            ierr,l5=psspy.brnmsc(19,227,'1','PCTCPA')
            l_5.extend([l5])
            ierr,l6=psspy.brnmsc(21,234,'1','PCTCPA')
            l_6.extend([l6])
            ierr,l7=psspy.brnmsc(24,241,'1','PCTCPA')
            l_7.extend([l7])
            ierr,l8=psspy.brnmsc(26,246,'1','PCTCPA')
            l_8.extend([l8])
            ierr,l9=psspy.brnmsc(31,253,'1','PCTCPA')
            l_9.extend([l9])
            ierr,l10=psspy.brnmsc(33,260,'1','PCTCPA')
            l_10.extend([l10])
            ierr,l11=psspy.brnmsc(36,267,'1','PCTCPA')
            l_11.extend([l11])
            ierr,l12=psspy.brnmsc(38,272,'1','PCTCPA')
            l_12.extend([l12])


            N=N+1

        path2="S:/RDS/New MV LV/LV3phase_fuseCB/HU_v2/Raw_output/%d" %(p)

        os.chdir(path2)

# print output in text files
        l_1 = str(l_1)[1 : -1];
        sys.stdout=open('L1.txt','a')
        print l_1
        l_2 = str(l_2)[1 : -1];
        sys.stdout=open('L2.txt','a')
        print l_2
```

```
l_3 = str(l_3)[1 : -1];
sys.stdout=open('L3.txt','a')
print l_3
l_4 = str(l_4)[1 : -1];
sys.stdout=open('L4.txt','a')
print l_4
l_5 = str(l_5)[1 : -1];
sys.stdout=open('L5.txt','a')
print l_5
l_6 = str(l_6)[1 : -1];
sys.stdout=open('L6.txt','a')
print l_6
l_7 = str(l_7)[1 : -1];
sys.stdout=open('L7.txt','a')
print l_7
l_8 = str(l_8)[1 : -1];
sys.stdout=open('L8.txt','a')
print l_8
l_9 = str(l_9)[1 : -1];
sys.stdout=open('L9.txt','a')
print l_9
l_10 = str(l_10)[1 : -1];
sys.stdout=open('L10.txt','a')
print l_10
l_11 = str(l_11)[1 : -1];
sys.stdout=open('L11.txt','a')
print l_11
l_12 = str(l_12)[1 : -1];
sys.stdout=open('L12.txt','a')
print l_12
sys.stdout=open('L12.txt','a')
print ''

p+=1
```

Appendix C: Publications

- **Md. I. M. Ridzuan**, I. H.-Gil, S. Z. Djokic, R. Langella, and A. Testa, "Incorporating Regulator Requirements in Reliability Analysis of Smart Grids. Part 1: Input Data and Models," *5th IEEE PES Innovative Smart Grid Technologies (ISGT) Europe 2014 Conference*, 12-15 October, 2014, Istanbul, Turkey.
- **Md. I. M. Ridzuan**, I. H.-Gil, S. Z. Djokic, R. Langella, and A. Testa, "Incorporating Regulator Requirements in Reliability Analysis of Smart Grids. Part 2: Scenarios and Results," *5th IEEE PES Innovative Smart Grid Technologies (ISGT) Europe 2014 Conference*, 12-15 October, 2014, Istanbul, Turkey.
- **M. I. M. Ridzuan**, I. H.-Gil, and S. Z. Djokic,"Comparison of Analytical and Probabilistic Reliability Assessment Methodologies for Offshore Renewable Generation Plants and Networks," *ASRANET International Conference on Renewable Energy*, 2014, Glasgow, United Kingdom.
- M. Y. Wu, **M. I. Ridzuan** and S. Z. Djokic, "Smart grid functionalities for improving reliability of rural electricity networks," *Mediterranean Conference on Power Generation, Transmission, Distribution and Energy Conversion (MedPower 2016)*, Belgrade, 2016, pp. 1-7.

Incorporating Regulator Requirements in Reliability Analysis of Smart Grids. Part 1: Input Data and Models

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***Abstract*—This paper is part one of a two-part series discussing how Regulator requirements for continuity of supply could be incorporated in the reliability analysis of existing electricity networks and future "smart grids". The paper uses examples of overall and guaranteed standards of performance from the UK and Italy, specifying requirements that network operators should satisfy with respect to excessively long and/or too frequent supply interruptions. Besides the relevant Regulator requirements, this paper presents input data, parameters and models required for comprehensive reliability assessment, while Part 2 paper presents scenarios and results for test network based on both analytical and probabilistic reliability procedures.**

***Index Terms*-- Power system modelling, power system reliability, security and quality of supply.**

I. INTRODUCTION

System Reliability Performance is one of the most important aspects of both existing electricity networks and future "smart grids". Distribution network operators (DNOs) have to carefully elaborate their operation, maintenance and planning strategies, in order to ensure that frequency and duration of supply interruptions experienced by their customers are within reliability targets and limits imposed by Energy Regulators, which are typically specified as the overall and guaranteed standards of performance (e.g. [1]-[3] in the UK, or [4]-[5] in Italy). This is one of main DNOs' priorities, as they will be penalized, rewarded or liable for compensation based on the actually achieved reliability performance.

This paper, which is a part one of a two-part series, presents input data, parameters and models required for a comprehensive reliability assessment of both existing electricity networks and future "smart grids", which could take into account Regulator requirements for continuity and quality of supply. This is illustrated in the paper using the examples of the overall and guaranteed standards of performance from the UK and Italy, specifying requirements that DNOs should satisfy with respect to excessively long and/or too frequent supply interruptions. Part 2 paper, [6], presents scenarios and results of both analytical and probabilistic procedures for reliability performance assessment of a typical urban distribution network.

Assessment of system reliability performance is not a simple task, as it requires time-consuming studies and significant amount of data and information about power components and network characteristics, Table I. Regarding the power components, basic input data are mean fault rates and mean repair times, as well as the components' types of faults, which are discussed in Section II of this paper. Section II also gives an overview of typical protection settings and loading conditions used for the analysis. Section III lists Regulator requirements for continuity and quality of supply in the UK and Italy, while Section IV describes test network. All that is used in Part 2 paper [6], which presents results for analytical and probabilistic assessment of reliability of test network for several scenarios, including some "smart grid" functionalities.

TABLE I
RELEVANT INPUT DATA/PARAMETERS FOR NETWORK RELIABILITY ASSESSMENT.

Power Components			Network Characteristics (including types and settings of protection systems, Section II.A)				
Fault Rates	**Repair Times**	**Fault Types**	**Configuration**	**Switching**	**Back-up Supply**	**LV Network representation**	**Loading Conditions**
Mean values (Section II.B) (and assumed distributions)		No distinction (all permanent)	Radial	Manual	No (not available)	No	Constant (e.g. peak)
Variable values (Sections II.C-D) (and assumed distributions)		Permanent vs. transient (Section II.E)	Meshed	Automatic	Yes (manual or automatic transfer)	Yes (equivalent or detailed)	Variable (Section II.F) (e.g. actual load profiles)

II. INPUT DATA AND PARAMETERS

A. Protection Settings

The fault clearance times are determined by the settings of the protection system. Table II lists protection settings used in this paper (typical for the UK DNOs, [7]-[8]).

TABLE II
TYPICAL FAULT CLEARANCE TIMES (UK-BASED, [7] AND [8]).

Power Component	Voltage Level (kV)	Protection System	Fault clearance time (s)
Overhead Lines	11	Circuit breaker with auto-reclosing	10-120
	33	Circuit breaker with auto-reclosing	90
Cables	11	Circuit breaker with auto-reclosing	up to 3
	33	Circuit breaker with auto-reclosing	90
Transformers	11/0.4	Fuse	repair time
	33/11	Circuit breaker with auto-reclosing	0.15-10
Buses	0.4	Fuse	repair time
	11	Circuit breaker	0.15
	33	Circuit breaker	0.15

B. Mean Fault Rates and Mean Repair Times

Mean fault rates and mean repair times are two basic inputs of practically all procedures for system reliability assessment. In available literature, reported values of these two input data vary in wide ranges (based on the characteristics and locations of networks, types and characteristics of components, as well as their operating conditions). Table III presents statistics of mean fault rates and mean repair times from two main sources: UK-related values reported in [9] and from other sources, [10]-[17].

TABLE III
MEAN FAULT RATES AND MEAN REPAIR TIMES OF POWER COMPONENTS.

Power Component	Voltage Level (kV)	Mean fault rate λ_{mean} (faults/year) [9]	Mean fault rate λ_{mean} (faults/year) [10]-[17]	Mean repair time μ_{mean} (hours/fault) [9]	Mean repair time μ_{mean} (hours/fault) [10]-[17]
Overhead Lines	<11	0.168	0.21	5.7	-
	11	0.091	0.1	9.5	-
	33	0.034	0.1	20.5	55
Cables	<11	0.159	0.19	6.9	85
	11	0.051	0.05	56.2	48
	33	0.034	0.05	201.6	128
Transformers	11/0.4	0.002	0.014	75	120
	33/0.4	0.01	0.014	205.5	120
	33/11	0.01	0.009	205.5	125
Buses	0.4	-	0.005	-	24
	11	-	0.005	-	120
	>11	-	0.08	-	140
Circuit Breakers	0.4	-	0.005	-	36
	11	0.0033	0.005	120.9	48
	33	0.0041	-	140	52
Fuses	0.4 & 11	0.0004	-	35.3	-

C. Daily Variations in Fault Rate Values

Based on the analysis presented in [18], this paper uses a realistic interruption probability model derived from the two-year recordings of short and long interruptions (SIs and LIs) from two European DNOs, Fig. 1. Daily probability profiles of both SIs and LIs are first represented with the theoretical interruption probability model, dashed red line in Fig. 1 described with (1), and then used to estimate daily variations in reported mean fault rate values (λ_{mean}) of power components from Table III, shown in Fig. 2 and expressed by (2). This allows to include a more accurate analysis of SIs and Lis in reliability procedures used in Part 2 paper, [6].

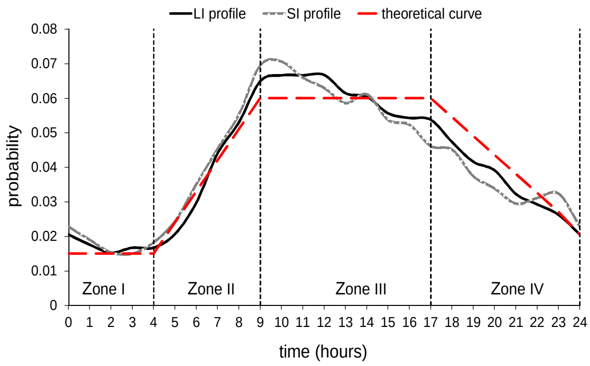

Figure 1. Daily probabilities of long/short interruptions (LI/SI), [18].

$$f(t)=\begin{cases} 0.015, & 0\le t\le 4 \\ m_1 t+n_1, & 4<t\le 9 \\ 0.06, & 9<t\le 17 \\ m_2 t+n_2, & 17<t<24 \end{cases} \tag{1}$$

where t is hour of the day and four coefficients for linear parts are: m_1=0.009, m_2=-0.00643, n_1=-0.021 and n_2 = 0.1693.

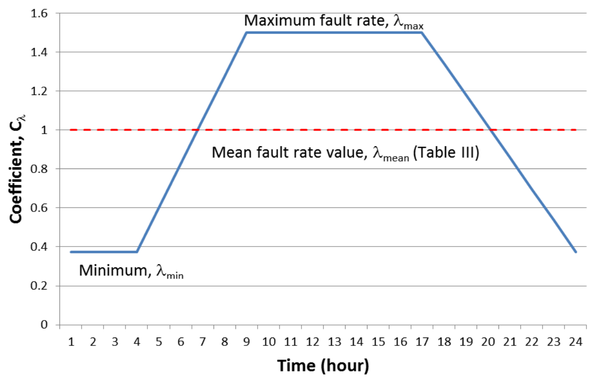

Figure 2. Estimated daily variations in fault rates.

Based on Table III and Figs. 1 and 2, daily variations in fault rates can be expressed as.

$$\lambda(t)=\lambda_{mean}\cdot C_\lambda(t)=\begin{cases} \lambda_{mean}\cdot 0.375=\lambda_{\min}, & 0\le t\le 4 \\ \lambda_{mean}\cdot(0.225t-0.525), & 4<t\le 9 \\ \lambda_{mean}\cdot 1.5=\lambda_{\max}, & 9<t\le 17 \\ \lambda_{mean}\cdot(4.232-0.161t), & 17<t<24 \end{cases} \tag{2}$$

where t is hour of the day.

D. Daily Variations in Repair Time Values

Similarly to the daily variations in fault rates, mean repair times from Table III (μ_{mean}) are estimated to vary in a range between the maximum value (μ_{max}, corresponding to night-time, when availability of repair crew is lower) and minimum value (μ_{min}, corresponding to day-time, when availability of repair crew is higher), Fig. 3 and (3).

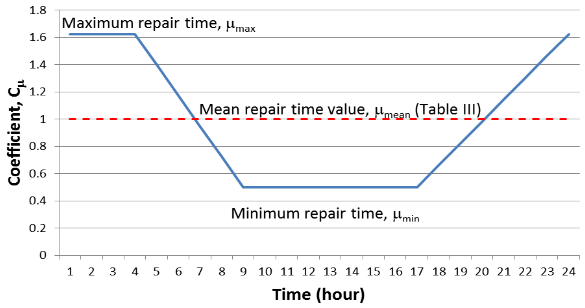

Figure 3. Estimated daily variations in repair times.

$$\mu(t) = \mu_{mean} \cdot C_{\mu}(t) = \begin{cases} \mu_{mean} \cdot 1.625 = \mu_{\max}, & 0 \le t \le 4 \\ \mu_{mean} \cdot (2.525 - 0.225t), & 4 < t \le 9 \\ \mu_{mean} \cdot 0.5 = \mu_{\min}, & 9 < t \le 17 \\ \mu_{mean} \cdot (0.161t - 2.232), & 17 < t < 24 \end{cases} \quad (3)$$

where t is hour of the day.

E. Fault Types

The classification of customer interruptions into SIs and LIs is not possible without, for instance, modelling the applied protection systems. A simple way to make clear distinction between short and long supply interruptions of customers is to define a uniform distribution and link it to the system reliability assessment procedure. For that purpose, past recordings collected from 14-UK DNOs between 2005 and 2009 [19] were analysed, identifying that 54% of supply interruption events were caused by temporary faults (i.e. SIs), and 46 % were due to permanent faults (i.e. LIs).

F. Loading Conditions

Typical residential load profile used for the reliability analysis is shown in Fig. 4. The inclusion of actual load profiles in the reliability analysis is important, as it may strongly impact the assessed system reliability performance.

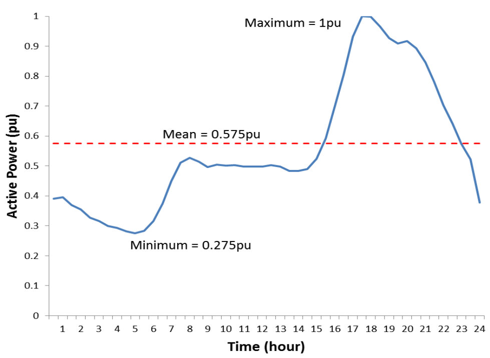

Figure 4. Typical residential load profile (day of maximum demand).

III. CONTINUITY OF SUPPLY REQUIREMENTS

Regulators usually define two main continuity of supply requirements: guaranteed standards of performance and overall standards of performance. The former should ensure that any single customer receive at least the minimum level of continuity of supply from the DNOs (protection of worst-served customers through the compensations for multiple and/or excessively long supply interruptions). The latter monitors DNO's performance at system level and is used as a basis for reward/penalties schemes regarding set targets for (system average) number of supply interruptions per year and per customer served (SAIFI), as well as (system average) duration of supply interruptions per year and per customer served (SAIDI). Additional links are maintained between the performance standards and DNOs' revenues and/or tariffs. As DNOs have to ensure that their networks are operated with respect to "standards performance" requirements, analysis presented in Part 2 paper [6] shows how these requirements could be incorporated in the reliability assessment procedures.

A. Regulator Requirements in the UK

The UK Security and Quality of Supply (SQS-UK) requirements [1] specify maximum times (i.e. maximum durations of LIs) allowed for restoring supply to at least a minimum group demand of the interrupted customers. Six group demand classes are defined based on the group demand ranges, for which maximum allowed durations of long interruptions and minimum demand that has to be restored within that time are specified in Table IV.

TABLE IV
SECURITY AND QUALITY OF SUPPLY REQUIREMENTS IN THE UK, SQS-UK [1].

Class	Corresponding Group Demand (GD)	Required supply restoration times & minimum demands to be met after first circuit outage
A	GD ≤ 1 MW	In repair time: GD
B	1 MW < GD ≤ 12 MW	a) Within 3 h: GD-1MW b) In repair time: GD
C	12 MW < GD ≤ 60 MW	a) Within 15 min: min{GD-12MW; 2/3 GD} b) Within 3 h: GD
D	60 MW < GD ≤ 300 MW	a) Immediately: GD-up to 20 MW b) Within 3 h: GD
E	300 MW < GD ≤ 1500 MW	Immediately: GD
F	GD > 1500 MW	According to transmission license security standard

Further to the requirements in Table IV, and in order to protect domestic (i.e. residential) and non-domestic customers from excessively long interruption events (i.e. those categories of customers that have no special contract or agreement with the DNOs regarding long interruptions), the UK Regulator specifies additional requirements for the duration and number of long interruptions. References [2] and [3] are main UK statutory instrument, specifying the allowed supply restoration times for up to 5,000 customers, more than 5,000 customers and in severe weather conditions. This is illustrated in Table V (only for normal system operating conditions) together with the corresponding compensations DNOs will pay directly to the customers (not to the Regulator), if supply is not restored within the specified time, [2] and [3].

TABLE V
THE UK GUARANTEED STANDARDS OF PERFORMANCE, GSP-UK, [2]-[3].

Supply Restoration Time		Compensation Paid to:	
No. of customers interrupted	**Maximum supply restoration time**	**Domestic customers**	**Non-domestic customers**
< 5,000*	18 h	£54	£108
	After each succeeding 12h	£27	
≥ 5,000*	24 h	£54	£108
	After each succeeding 12h	£27	
	Maximum	£216	
Multiple Interruptions**		**Compensation (all customers)**	
Four or more interruptions (≥ 4), each lasting at least three hours (≥ 3 h)		£54	

* This paper assumes that 5,000 customers correspond to about 12 MW of residential load demand.

** In any single year (12-month period) starting on the 1st of April.

B. *Regulator Requirements in Italy*

Similarly to the Regulator requirements in the UK, Tables VI and VII list Italian Supply Quality Standard (SQS-I) and Guaranteed Standards of Performance (GSP-I), [4]-[5].

TABLE VI
SUPPLY QUALITY STANDARD IN ITALY, SQS-I, [4].

Requirement	High Concentration (I > 50,000)*	Medium Concentration (5,000 < I ≤ 50,000)*	Low Concentration (I ≤ 5,000)*
Maximum supply restoration times (LV customers)	8 h	12 h	16 h
Maximum supply restoration times (MV customers)	4 h	6 h	8 h
Average number of interruptions	1 int/customer	2 int/customer	4 int/customer
Average duration of interruptions	25 min/customer	40 min/customer	60 min/customer

* I - number of inhabitants; this paper assumes that 5,000 inhabitants correspond to about 2,000 residential customers and around 5 MW of residential load demand.

TABLE VII
GUARANTEED STANDARDS OF PERFORMANCE IN ITALY, GSP-I, [5].

Customers interrupted	Criteria for compensation	Compensation
Domestic	If longer than SQS-I duration limit	€30
	For each succeeding 4h	€15
	Maximum	€300
LV & MV Non-domestic Non-public ≤ 100 kW	If longer than SQS-I duration limit	€150
	For each succeeding 4h	€75
	Maximum	€1,000
LV Non-domestic Non-public > 100 kW	If longer than SQS-I duration limit	€2/kW
	For each succeeding 4h	€1/kW
	Maximum	€3,000
MV Non-public > 100 kW	If longer than SQS-I duration limit	€1.5/kW
	For each succeeding 2h	€0.75/kW
	Maximum	€6,000
LV & MV With license for generation*	If longer than SQS-I duration limit	€0.15/kW
	For each succeeding 4h	€0.075/kW
	Maximum	€3,000

* It is assumed that for prosumers (producers-consumers) the maximum compensation between producers and consumers is applied

IV. GENERIC TEST NETWORK MODEL

Test network used to illustrate reliability analysis in Part 2 paper [6] is a generic urban UK MV distribution network configuration, Fig. 5, supplying only low voltage (LV) domestic customers, Fig. 6 (for more detail see [20]-[21]).

A. *Urban MV Network*

The urban MV network in Fig. 5 presents a meshed configuration, but, in normal conditions, the urban network configuration operates radially and becomes meshed if the switch, normally open between two radial feeders, is closed. The network also has an alternative supply point at 11kV at the end of the radial feeders (providing unrestricted support).

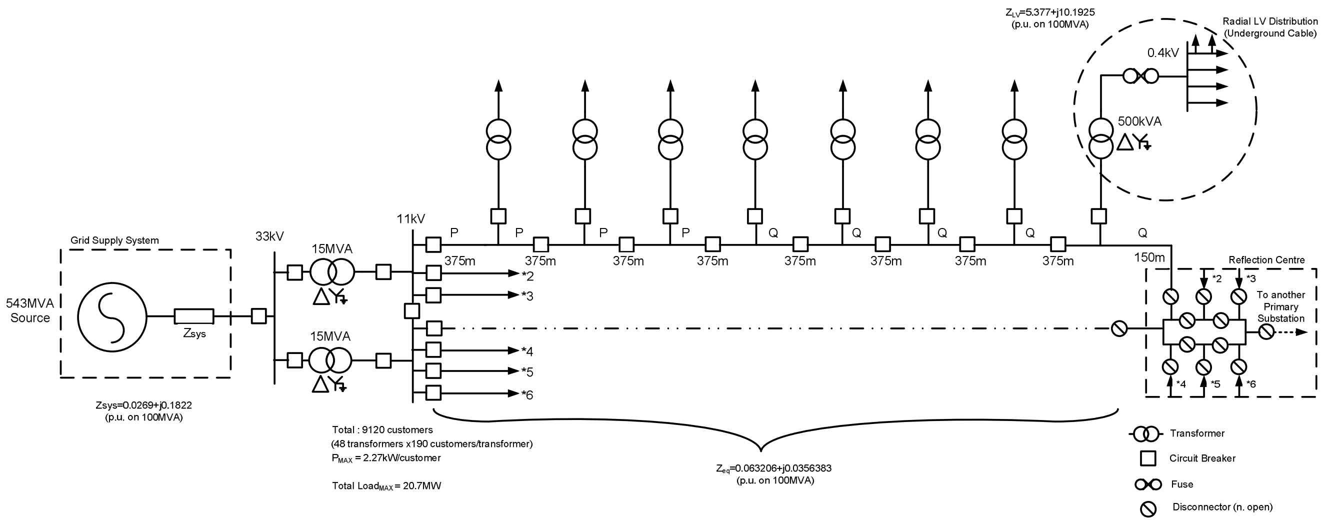

Figure 5. Test MV Urban Network [20]-[21].

B. Urban LV Network

Each of the 6 x 8 = 48 LV bulk load supply points connected through a 500kVA 11/0.4kV transformer in Fig. 5 supplies an identical LV urban network with 190 individual LV customers, Fig. 6.

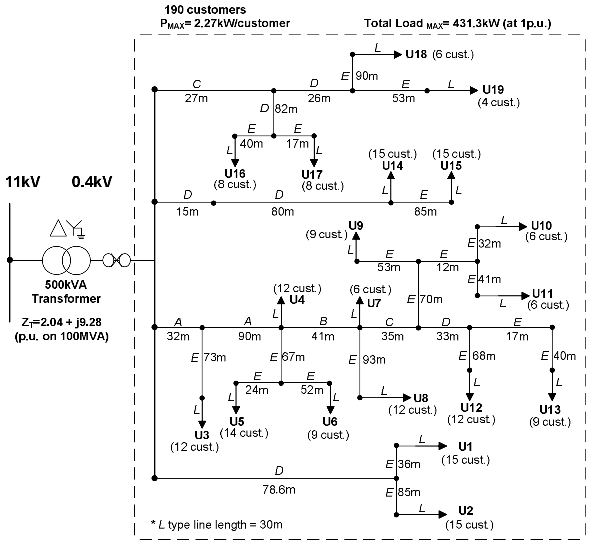

Figure 6. Test LV Urban Network [20]-[21].

Generic urban LV distribution network in Fig. 6 is operated in radial configuration and supplied from the infeeding 11/0.4 kV substation/transformer (secondary side is fuse protected), with a number of LV feeders supplying one or more lateral spurs and service connections (3-phase or 1-phase). Although the connection of multiple single-phase customers in practice makes the LV networks inherently unbalanced, loading conditions at each LV network node in Fig. 6 are modelled as symmetrical and in accordance with Fig. 4.

In urban areas, load density is high and line lengths are shorter (usually less than 10km) and underground cables are typically used to improve reliability of supply and for aesthetical reasons. As mentioned, detailed and updated specifications for all LV and MV network components and configurations are modelled based on data collected from the UK and European DNOs and manufacturers of power equipment, with more detail provided in [20] and [21].

V. CONCLUSIONS

This paper, which is part one of a two-part series, presents input data, parameters and models required for a comprehensive reliability assessment of both existing electricity networks and future "smart grids", which could take into account Regulator requirements for continuity and quality of supply. This is illustrated using the examples of the overall and guaranteed standards of performance from the UK and Italy, specifying requirements that DNOs should satisfy with respect to excessively long and/or too frequent supply interruptions. The analysis continues in Part 2 paper, [6], which presents scenarios and results of both analytical and probabilistic procedures for assessing reliability performance of modelled generic urban distribution network.

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Incorporating Regulator Requirements in Reliability Analysis of Smart Grids. Part 2: Scenarios and Results

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***Abstract*—This is the second paper in a two-part series discussing how Regulator requirements for continuity of supply could be incorporated in the reliability analysis of existing electricity networks and future "smart grids". Part 1 paper presents input data, parameters and models required for a comprehensive assessment of system reliability performance, including an overview of the overall and guaranteed standards of performance in the UK and Italy. This paper presents scenarios and results of both analytical and probabilistic reliability assessment procedures for the test network introduced in Part 1 paper.**

***Index Terms*-- Power system modelling, power system reliability, security and quality of supply.**

I. INTRODUCTION

Distribution network operators (DNOs) have to carefully elaborate operation, maintenance and planning strategies of their networks, in order to ensure that both frequency and duration of supply interruptions experienced by their customers are within the reliability targets and limits imposed by Energy Regulators. After presenting overall and guaranteed standards of performance from the UK and Italy ([1]-[5]), as well as input data, parameters and models in Part 1 paper, [6], this paper presents scenarios and results of both analytical and probabilistic methodologies for a comprehensive reliability assessment of existing electricity networks and future "smart grids". Particular attention is paid to the assessment of the DNO's risks of not satisfying the corresponding Regulator requirements.

Presented analysis considers several scenarios, in order to take into account various Regulator-imposed requirements for the number and/or duration of supply interruptions, inclusion of actual load profiles, daily variations in probabilities of components' faults and their repair times, as well as the various options for DNO's response to supply interruptions through network reconfiguration, provision of alternative supply and implementation of manual or automatic switching.

II. RELIABILITY ASSESSMENT METHODOLOGIES

Over the last decades, the concept of reliability assessment evolved into the comprehensive approaches for evaluating various engineering strategies, typically linked to system planning, operation and maintenance studies. The meaning of reliability, which was initially expressed as the ability of a component to operate without faults during its lifetime and as specified by the manufacturer, has been generalized and now receives different connotations in engineering applications. This change is emphasized by the context in which reliability analysis of modern electricity networks is not directly assigned to individual components in terms of frequency and duration of their failures, but is extended and typically refers to the performance assessment of a whole system, subsystem, or part of a system supplying electricity customers.

Recent statistics indicate that the reliability assessment methods used by the DNOs are not always successfully implemented, even though DNOs may be confident with the methods they use. For example, more than 14% of DNOs have recently been penalized in the UK for not achieving Regulator-specified limits for customer interruptions, while 50% of them have not been able to meet imposed targets for duration of supply interruptions [7]. Although several factors have been suggested as possible reasons for such underperformance, one of the main issues is related to the methods DNOs use to estimate the frequency and duration of customer interruptions, as well as the corresponding risks of penalties for not satisfying Regulator-imposed targets.

Linear regression methods, which rely on extrapolation or interpolation of past reliability statistics for a given network, may not provide correct reliability assessment, because network configuration has changed, or simply because the experienced interruption events occur randomly, so some events, or combinations of events, did not occur previously. Two general approaches are considered as feasible and practical alternatives to linear regression methods: analytical and probabilistic reliability assessment methodologies.

A. Analytical Reliability Assessment Approaches

Among the several techniques developed over the past years for the assessment of reliability performance, analytical approaches are often used for network planning or system security studies (e.g. “n-1 or n-2 security criteria”), as well as for evaluating network contingencies and system capacity/reserve requirements. It is generally assumed, however, that analytical reliability assessment approaches cannot directly or fully model inherently stochastic nature of system faults, or significant variations in fault repair times, or equally wide range of changes in system loading conditions.

Analytical reliability assessment approaches are based on mathematical models, which characterize analysed network in terms of the specified input data, typically limiting outputs to one set of results, e.g. mean values of reliability indices, corresponding to specified input mean data. In that way, analytical approaches offer only a general “snapshot” characterization of the analysed system, as they will always provide the same set of output results for the same set of input data, parameters and models. This is significant difference from probabilistic methods, which enable to perform a more comprehensive evaluation of system reliability with output reliability indices expressed as probability distributions (showing the ranges of their variations), rather than one set of output values and results (typically mean values).

B. Probabilistic (Monte Carlo) Reliability Approaches

Probabilistic reliability assessment procedures are widely recognized as more suitable for the analysis of system reliability performance, particularly in terms of their ability to model stochastic and inherently unpredictable variations of input parameters and data (e.g. fault rates and repair times) with their assumed probability distributions. Furthermore, probabilistic reliability assessment approaches allow to model a wide range of variations of practically all input parameters and data in one or few simulation/calculation set-ups, without the need to repeat calculation after a change in input data.

Although probabilistic reliability assessment procedures are more difficult for implementation (particularly in complex large-scale systems), they provide more accurate results than linear regression methods and more detailed results than analytical approaches. The most frequently used probabilistic reliability assessment approach is the inverse transform method, also known as Monte Carlo Simulation (MCS, [8]). Besides network modelling, conventional MCS analysis requires statistical information on fault rates and repair times of faulted power components as input data. Network models and fault rates of power components are used to establish which customers will be interrupted (and how frequently), whereas repair times of faulted components and network protection, reconfiguration, switching and alternative supply functionalities are used to estimate durations of corresponding supply interruptions. The outputs of the MCS analysis are reliability indices, which are typically presented as probability distributions with the corresponding mean values.

C. Considered Scenarios

Table I provides descriptions of different scenarios used for reliability analysis of test network from Part 1 paper [6].

TABLE I
DESCRIPTIONS OF ANALYSED SCENARIOS.

Description of Scenarios
SCENARIO SC-1: Times for transferring to alternative supply and for reconfiguration switching are in accordance with the UK Security of Supply requirements (SQS-UK, Table IV in Part 1 paper, [6])
SC-1A: MV network only (no representation of LV network)
SC-1B: MV & LV network (LV represented with equivalent values)
SCENARIO SC-2: All long interruptions (including transfer to alternative supply and reconfiguration) last exactly 18 hours (in accordance with the UK Guaranteed Standards Performance, GSP-UK for maximum duration of interruptions, Table V in Part 1 paper, [6])
SC-2A: MV network only (no representation of LV network)
SC-2B: MV & LV network (LV represented with equivalent values)
SCENARIO SC-3: All long supply interruptions (including transfer to alternative supply and reconfiguration switching) last exactly 12 hours (in accordance with Italian Guaranteed Standards Performance, GSP-I, Table VII in Part 1 paper, [6])
SC-3A: MV network only (no representation of LV network)
SC-3B: MV & LV network (LV represented with equivalent values)
SCENARIO SC-4: Worst served customer has exactly four supply interruptions, of which three are exactly 18 hours and one is 3 hours (in accordance with the UK Guaranteed Standards Performance, GSP-UK for both maximum number and duration of supply interruptions, Table V in Part 1 paper, [6])
SC-4A: MV network only (no representation of LV network)
SC-4B: MV & LV network (LV represented with equivalent values)
SCENARIO SC-5: SAIFI=2 int/cust/year and SAIDI=40min/cust/year benchmark targets are in accordance with Italian Supply Quality Standard, SQS-I, Table VI in Part 1 paper, [6]
SC-5A: MV network only (no representation of LV network)
SC-5B: MV & LV network (LV represented with equivalent values)
SCENARIO SC-6: Times for transfer to alternative supply and for reconfiguration switching are exactly 3 minutes (“smart grid” switching functionality, changing some of long interruptions into the short ones)
SC-6A: MV network only (no representation of LV network)
SC-6B: MV & LV network (LV represented with equivalent values)

In Table I, Scenarios SC-1A and SC-1B represent existing MV and LV network configurations and functionalities, which are in accordance with security of supply requirements (the UK-based are applied, but Italian are similar). This means that MV network should have switching functionalities for transferring to alternative supply and for reconfiguration, as otherwise large numbers of customers will be exposed to excessively long supply interruptions (determined by mean repair times of network components). Scenarios 2A/2B to 5A/5B represent various guaranteed standards of performance and supply quality requirements, which will be used for analytical approach and formulation of corresponding limits and thresholds against which risk of penalty will be assessed after probabilistic results are obtained. Finally, Scenarios SC-6A and SC-6B represent “smart grid” scenario in which automatic remote-controlled switching is implemented in MV network (LV network is still protected only by the fuses).

III. LV NETWORK REPRESENTATION

Typically, reliability analysis is performed with respect to supply interruptions of connected customers, which are usually expressed and quantified in terms of the continuity of supply at bulk load supply points (typically at MV level). The main reason for neglecting LV networks (and LV customers) is that their inclusion will result in a substantial increase of complexity and excessive computational requirements in case of probabilistic reliability assessment procedures. For example, reliability assessment of test MV network shown in Fig. 5 in Part 1 paper, [6] is related to 48 LV load points, while the whole analysed network, including LV parts (shown in Fig. 6 in Part 1 paper, [6]), consists of 48 x 190 = 9,120 LV load points/customers. Additional problem is that all supplied customers are LV-connected and results of analysis of only MV network should be carefully interpreted, as they otherwise might not be directly applicable to LV customers.

Representation of LV networks/customers for reliability analysis of MV and HV networks is discussed in detail in [9] and [10], where equivalent reliability models are based on analytical approach from [11], providing failure rate, λ_{eq}, and repair time, μ_{eq}, for equivalented LV network Fig. 6, [6]:

$$\lambda_{eq} = \sum_{i=1}^{N} \lambda_i \ , \qquad (1) \qquad\qquad \mu_{eq} = \frac{1}{N} \cdot \sum_{i=1}^{N} \mu_i \ . \qquad (2)$$

where: N-total number of components in the equivalented part of the system, each with mean failure rate, λ_i, and mean repair time, μ_i.

Values calculated with (1) and (2) are compared with the results of the probabilistic MCS approach, where mean fault rates and mean repair times of LV network components from Table III in Part 1 paper, [6] are modelled using exponential and Rayleigh distributions and simulated for the total duration of 10,000 years, Table II and Figs. 1-3.

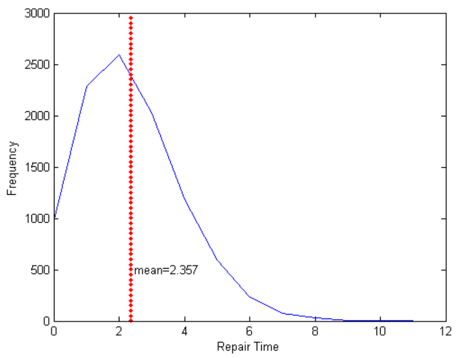


Figure 1. Probabilistic calculation of LV network equivalent data (10,000 years of simulations, exponential distribution for input mean fault rates).

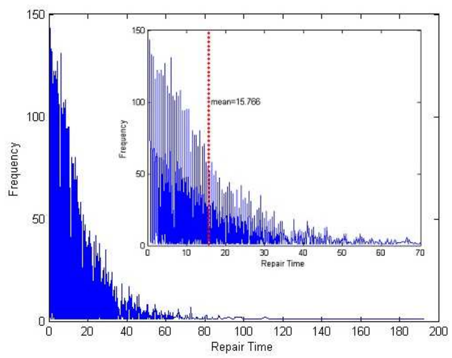


Figure 2. Probabilistic calculation of LV network equivalent data (10,000 years of simulations, exponential distribution for input mean repair times).

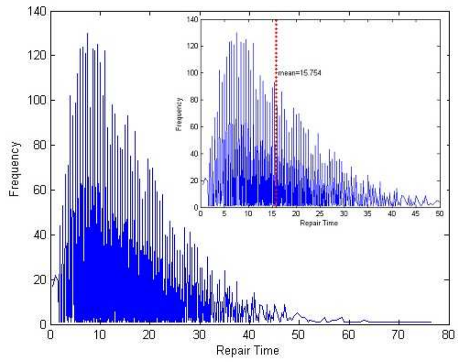


Figure 3. Probabilistic calculation of LV network equivalent data (10,000 years of simulations, Rayleigh distribution for input mean repair times).

TABLE II
COMPARISON OF LV NETWORK EQUIVALENT FAULT RATES AND REPAIR TIMES (ANALYTICAL AND PROBABILISTIC APPROACHES).

LV Network Parameter	**Analytical**	**Probabilistic**	
		(exponential distribution)	**(Rayleigh distribution)**
Equivalent fault rate, λ_{eq}	2.373	2.357	/
Equivalent repair time, μ_{eq}	15.933	15.766	15.754

IV. ANALYTICAL RELIABILITY ASSESSMENT

In order to assess the ranges of variations of output reliability indices, analytical approach should be implemented a number of times, where variations in each input data, resulting in a single set of output values, should be modelled and calculated as a succession of selected cases.

TABLE III
ANALYTICAL APPROACH, SCENARIOS SC-1A TO SC-6A (MV NETWORK ONLY, 48 LOAD POINTS/CUSTOMERS).

Reliability Indicator	**Scenario**	**Mean Load. Conditions**			**Max. Load. Conditions**		
		λ_{min} μ_{max}	λ_{mean} μ_{mean}	λ_{max} μ_{min}	λ_{min} μ_{max}	λ_{mean} μ_{mean}	λ_{max} μ_{min}
SAIFI	**SC-1A**						
	SC-2A	0.0644	0.1716	0.2574	0.0997	0.2658	0.3987
	SC-3A						
	SC-4A	2.8942			3.2086		
	SC-5A	2.0			2.0		
	SC-6A	0.0405	0.1080	0.1620	0.0758	0.2022	0.3033
SAIDI	**SC-1A**	0.9364	1.5366	1.1524	1.1086	1.8192	1.3644
	SC-2A	1.1584	3.089	4.6334	1.7943	4.7847	7.1771
	SC-3A	0.7722	2.0593	3.089	1.1962	3.1898	4.7847
	SC-4A	48.15			52.619		
	SC-5A	0.6667			0.6667		
	SC-6A	2.6521	4.3522	3.2641	4.1039	6.7346	5.0509
MAIFI	**SC-1A**						
	SC-2A	0.0756	0.2015	0.3022	0.117	0.3121	0.4681
	SC-3A						
	SC-4A	3.3976			3.7666		
	SC-5A	2.3478			2.3478		
	SC-6A	0.0994	0.2651	0.3976	0.1409	0.3756	0.5635
CAIDI	**SC-1A**	14.55	8.9539	4.477	11.1212	6.8438	3.4219
	SC-2A	18.0	18.0	18.0	18.0	18.0	18.0
	SC-3A	12.0	12.0	12.0	12.0	12.0	12.0
	SC-4A	16.6367			16.3995		
	SC-5A	0.3333			0.3333		
	SC-6A	65.479	40.295	20.148	54.119	33.304	16.652

Tables III and IV show values for most common reliability indices (SAIDI, SAIFI, MAIFI and CAIDI) calculated using analytical approach for test network, for mean and maximum loading conditions and pairs of correlated minimum, mean and maximum fault rates/repair times (Figs. 2-6, Part 1 paper [6]).

TABLE IV
ANALYTICAL APPROACH , SCENARIOS SC-1B TO SC-6B (MV & LV NETWORKS, 9120 LOAD POINTS/CUSTOMERS).

Reliability Indicator	Scenario	Mean Load. Conditions			Max. Load. Conditions		
		λ_{min} μ_{max}	λ_{mean} μ_{mean}	λ_{max} μ_{min}	λ_{min} μ_{max}	λ_{mean} μ_{mean}	λ_{max} μ_{min}
SAIFI	SC-1B	0.0025	0.0066	0.0099	0.0027	0.0071	0.0107
	SC-2B						
	SC-3B						
	SC-4B	0.0200			0.0201		
	SC-5B	2.0			2.0		
	SC-6B	0.0024	0.0063	0.0095	0.0025	0.0068	0.0102
SAIDI	SC-1B	0.0594	0.0975	0.0732	0.0603	0.099	0.0743
	SC-2B	0.0447	0.1192	0.1787	0.048	0.1281	0.1921
	SC-3B	0.0298	0.0794	0.1192	0.032	0.0854	0.1281
	SC-4B	0.2969			0.2971		
	SC-5B	0.6667			0.6667		
	SC-6B	0.1516	0.2488	0.1866	0.1354	0.2222	0.1666
MAIFI	SC-1B	0.0029	0.0078	0.0117	0.0031	0.0084	0.0125
	SC-2B						
	SC-3B						
	SC-4B	0.0235			0.0236		
	SC-5B	2.3478			2.3478		
	SC-6B	0.0030	0.0081	0.0121	0.0033	0.0087	0.0130
CAIDI	SC-1B	23.94	14.732	7.3662	22.6116	13.9148	6.9574
	SC-2B	18.0	18.0	18.0	18.0	18.0	18.0
	SC-3B	12.0	12.0	12.0	12.0	12.0	12.0
	SC-4B	14.835			14.794		
	SC-5B	0.3333			0.3333		
	SC-6B	64.168	39.488	19.744	53.110	32.683	16.342

Following similar analytical approach, Figs. 4 and 5 show in more detail daily variations in SAIFI and SAIDI index values (for estimated variations of fault rates and repair times and loading conditions shown in Figs. 2-4 in Part 1 paper [6]).

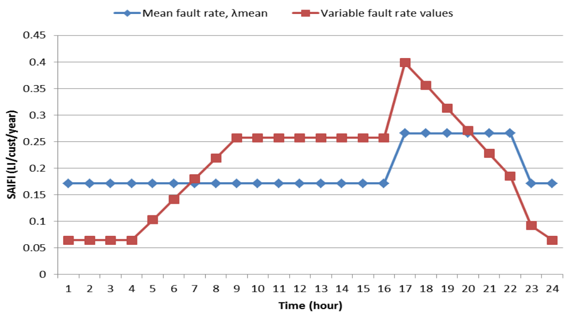


Figure 4. Daily variations in analytically calculated SAIFI values, SC-1A (mean and variable fault rates for actual load profile, MV network only).

As previously discussed, the most prominent feature of analytical reliability assessment approaches is that they will provide one single set of output values for a given or specified set of input data and parameters. Exactly that feature is used in this paper for a simple and straightforward inclusion of Regulator continuity of supply requirements (see Section III in Part 1 paper, [6]) in the reliability assessment procedures.

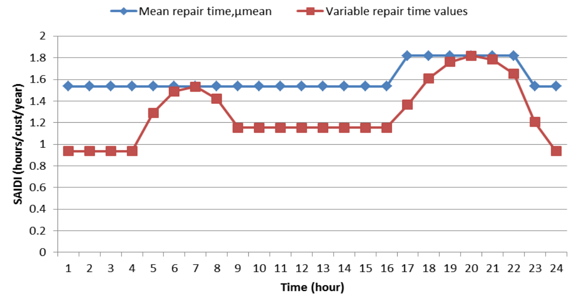
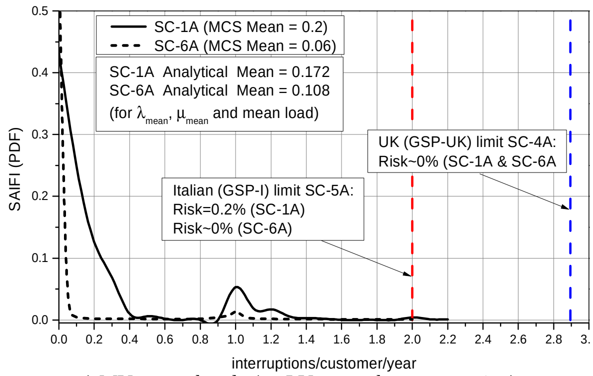


Figure 5. Daily variations in analytically calculated SAIDI values, SC-1A (mean and variable fault rates for actual load progile, MV network only).

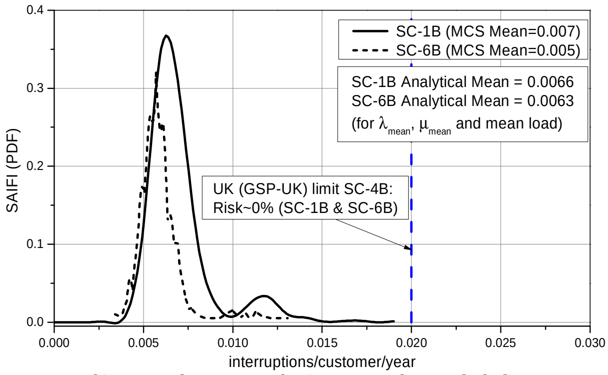
To incorporate selected Regulator requirements, analytical approach should use as input data actual limits for continuity of supply exactly as specified by Regulator. For example, to assess reliability of MV and LV networks from Figs. 5 and 6 in Part 1 paper, [6], with respect to GSP-UK, which requires DNOs to pay compensation to all customers exposed to supply interruptions longer than 18 hours (Table V in Part 1 paper, [6]), it is assumed in Scenarios SC-2A and SC-2B that every faulted component will have repair time of exactly 18 hours, with same duration applied for transfer to alternative supply and time required for network reconfiguration. In that way, the worst possible network reliability performance for which there will still be no penalty incurred due to supply interruptions longer than 18 hours will be calculated. This is illustrated in Tables III and IV, where for Scenarios SC-2A and SC-2B CAIDI is exactly 18 hours. Afterwards, these and other analytically calculated reliability indices are used as "benchmark limits" against which corresponding risks of penalty are directly assessed probabilistic reliability assessment (analytically calculated for pairs of values λ_{mean}-μ_{mean} and mean loading conditions are assumed to correspond to the mean values of the probabilistic/MCS results).

V. PROBABILISTIC RELIABILITY ASSESSMENT

Probabilistic approach is applied only for Scenarios SC-1A and SC-1B (representing existing MV and LV network configurations and functionalities) and for Scenarios SC-6A and SC-6B (representing "smart grid" functionalities applied to MV network). MCS-calculated SAIFI, SAIDI and CAIDI values for considered scenarios are shown in Figs. 6-8, together with all applicable limits calculated using analytical approach for the corresponding Regulator requirements from Scenarios SC-2A and SC-2B to Scenarios SC-5A/5B).

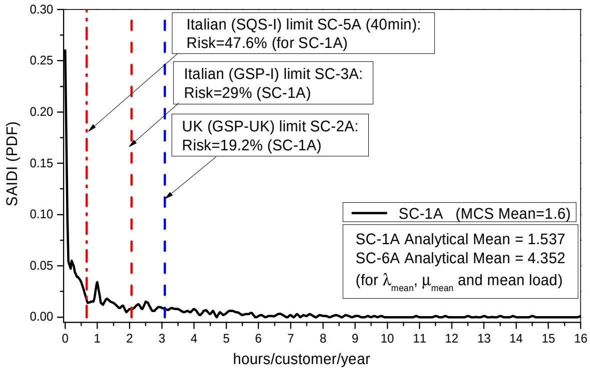


a) MV network only (no LV network representation)

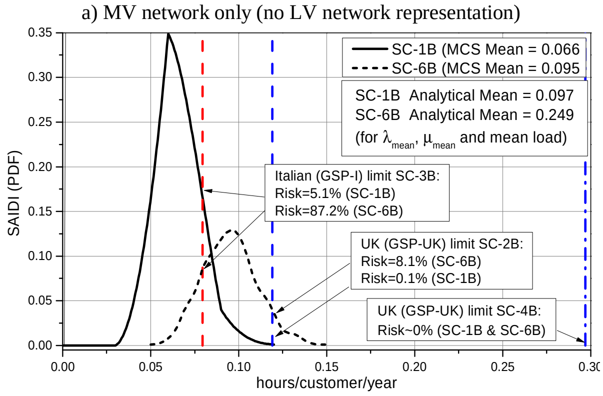


b) MV and LV networks (LV equivalent included)

Figure 6. Comparison of SAIFI values with indicated Regulator limits.



a) MV network only (no LV network representation)



b) MV and LV networks (LV equivalent included)

Figure 7. Comparison of SAIDI values with indicated Regulator limits.

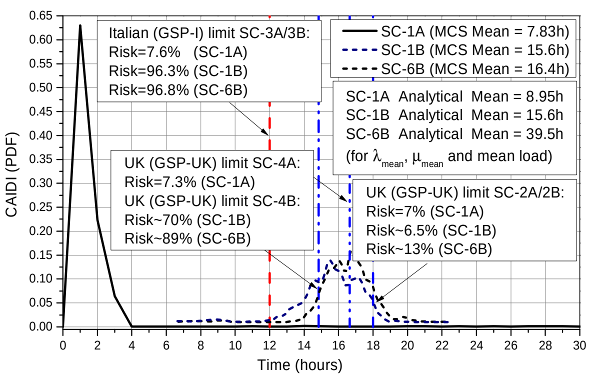


Figure 8. Comparison of CAIDI values with indicated Regulator limits.

VI. Discussion and Conclusions

Results for SAIFI suggest that the only risk of violating considered Regulator requirements for the number of long interruptions is with respect to Italian GSP-I limit of 2 int/cust/year (SC-5A, Fig. 6a, Risk=0.2%). However, if LV network is correctly represented (Fig. 6b), it is clear that this is no further the case (calculated SAIFI values are much lower).

Similarly, results in Fig. 7a for Scenario SC-1A indicate high risks of penalties regarding several Regulator limits, but results in Fig. 7b for Scenario SC-1B (with LV network modelled properly), suggest only 5% risk regarding Italian GSP-I of 12hrs. However, significant increase of SAIDI value is indicated in Fig. 7 for Scenario SC-6B, when "smart grid" automatic switching is applied. This is illustrated further in Fig. 8, which clearly shows that CAIDI values (i.e. average durations of long interruptions) increase after all faults that are previously cleared after 15min or 3hrs are now short interruptions due to <3min automatic switching. In other words, shorter duration long interruptions are no longer contributing to the average values, which are now around 16hrs (resulting in much higher risk of penalty regarding Italian SC-3A/3B limit of 12hrs and lower, but still notable risk regarding UK SC-2A/2B limit of 18hrs). The last results should be carefully interpreted, as the "smart grid" switching reduced number of long interruptions (Fig. 6), which now on average last longer. This also suggests that "smart grid" functionalities should be also implemented in LV network, in order to further reduce duration/number of long interruptions.

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COMPARISON OF ANALYTICAL AND PROBABILISTIC RELIABILITY ASSESSMENT METHODOLOGIES FOR OFFSHORE RENEWABLE GENERATION PLANTS AND NETWORKS

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ABSTRACT

Improving the reliability and availability of offshore generating plants and networks (i.e. reducing their revenue losses) requires correct assessment of the reliability of both the individual components and the complete offshore generation system. This paper presents the results of the reliability analysis of offshore generating plants and interconnecting MV/HV networks. Both analytical and probabilistic reliability calculation methods are implemented and compared during the assessment, in order to obtain a more confident estimation of the reliability performance. Besides the standard reliability indices (related to frequency and duration of faults/interruptions), other energy-related reliability indicators are presented and compared, in order to identify the best combination of network configurations, network interconnections and generation technologies. The benefits of each case (reduction of interrupted or curtailed energy outputs) are assessed against the actual cost.

1. INTRODUCTION

Continuity of power supply, expressed and assessed as the ability of a power system, or any of its component, to perform their functions as intended (i.e. to operate normally), is known as the reliability. System faults, and malfunctions of system components occur in inherently stochastic and unpredictable ways, which require use of probability and statistical theory during the reliability analysis, where both continuous and discrete variables and parameters should be used as the inputs for the analysis. Amongst the different indices and indicators that can be used for the system reliability performance analysis, of particular values are those that can be applied to both individual network/system components (e.g. a generator, or a transformer) and to the whole system, allowing to quantify impact of the particular components on the whole system reliability. In this context, concepts of reliability and availability of network components and of the whole offshore renewable generating system (ORGS) are analysed in this paper, which quantifies and compares ORGS reliability performance using the “Estimated Energy Not Supplied” (EENS) index. This approach allows for a straightforward assessment of the impact of different reliability and power quality events and disturbances, as it translates frequency and duration of downtime ORGS conditions into the electrical energy (MWh), which is either not produced or cannot be exported to the onshore grid. The presented analysis uses average value of the capacity factor of generating plants in ORGS of 40%, in order to produce conservative estimations.

2. RELIABILITY ANALYSIS: INPUT DATA

The reliability of ORGS can be assessed with confidence only if the relevant data for the analysis are presented as the statistically significant datasets, which are typically available after many years of operation. Although it can be generally concluded that currently available reliability data and information do not allow performing an in-depth analysis of the ORGS, an extensive review of available reports and other literature was performed in this paper in order to estimate main input parameters required for the reliability analysis of ORGS. For example, the results of several field studies from Reliawind project, representing in total 35,000 downtime events involving 350 wind turbines are compiled and processed in [1], indicating that power module (converter and associated switchgear and transformer) and wind turbines’ pitch control system are the most frequent causes of faults and downtimes. Power cables (inter-array and export cabling installations) were responsible for around 1%-5% of faults/downtimes. Reliability statistics is typically collected from 10-min average turbine and substation SCADA databases, fault logs per turbine and substation and monthly operational reports compiled by the wind farm operators and/or manufacturers. Tables 1 and 2 show reported values of main reliability analysis parameter, also giving minimum, maximum and average values of fault rates and mean repair times, which are used specifically for the analysis of the reliability performance of a typical medium size wind-based ORGS in this paper.

Table 1 Statistics on Fault Rates (with indicated minimum, maximum and average values), [2]-[12].

ORGS Part	Component	Failure rate (faults/year)													
		Reference											Min	Avg	Max
		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]			
Offshore (Internal)	Wind Turbine Generators		0.012	1	2		1.5	0.1					0.012	0.9224	2
	Nacelle Transformer (0.69/33kV)	0.0131	3.00E-05		0.007712	0.0131	0.0131	0.0131		3.00E-06			0.000003	0.008592	0.0131
	Tower cable	0.015				0.015	0.015			2.00E-02			0.015	0.01625	0.02
	MV Breaker	0.025					0.025	0.025			0.00306		0.00306	0.019515	0.025
	MV Switch/Disconnector	0.025			0.000524	0.025	0.025				0.00012		0.00012	0.015129	0.025
Offshore (External)	MV Breaker 33kV				0.000823	0.025		0.025					0.000823	0.016941	0.025
	MV Breaker 70kV								0.032				0.032	0.032	0.032
	HV Breaker								0.032	1.25			0.032	0.641	1.25
	HV Disconnector										0.00002		0.00002	0.00002	0.00002
	MV Busbar 33kV		5.00E-04			0.015					0.00011		0.00011	0.005203	0.015
	HV Busbar		1.25					0.005			0.00018		0.00018	0.418393	1.25
	MV Cable 33kV		8.00E-03		0.001266		0.015	0.015	0.008	7.43E-03			0.001266	0.009116	0.015
	HV Cable		0.95	0.00021		0.015			0.008	9.45E-03	8.80E-04	8.00E-02	0.00021	0.151934	0.95
	Transformer (33/132kV)		0.035		0.006	0.0131		0.02		3.44E-02	1.24E-02	3.00E-02	0.006	0.021553	0.035
Onshore	HV Cable			0.00021									0.00021	0.00021	0.00021
	HV Breaker								0.05				0.05	0.05	0.05

Table 2 Statistics on Mean Repair Times (with indicated minimum, maximum and average values), [2]-[12].

ORGS Part	Component	Mean Repair Times (hours/fault)													
		Reference											Min	Avg	Max
		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]			
Offshore (Internal)	Wind Turbine Generators		720	144	144		490	240					144	347.6	720
	Nacelle Transformer (0.69/33kV)	240	240		144	240	240	240		60			60	200.57	240
	Tower cable	240				240	240			48			48	192	240
	MV Breaker	240					72	240			240		72	198	240
	MV Switch/Disconnector	240			144	240	240				240		144	220.8	240
Offshore (External)	MV Breaker 33kV				144	240		144					144	176	240
	MV Breaker 70kV								720				720	720	720
	HV Breaker								720	20			20	370	720
	HV Disconnector										240		240	240	240
	MV Busbar 33kV		96			1440					240		96	592	1440
	HV Busbar		72					144			240		72	152	240
	MV Cable 33kV		288		144		1440	288	2160	192			144	752	2160
	HV Cable		720	144		1440			720	504	2160	1440	144	1018.29	2160
	Transformer (33/132kV)		720		144	240		400		504	1980	4320	144	1186.86	4320
Onshore	HV Cable			120									120	120	120
	HV Breaker								50				50	50	50

3. TYPICAL ORGS CONFIGURATIONS

A number of published reports and references, as well as the actual ORGS' is reviewed and investigated, in order to identify the typical network layouts, configurations and components. These are illustrated in Figs. 1-7.

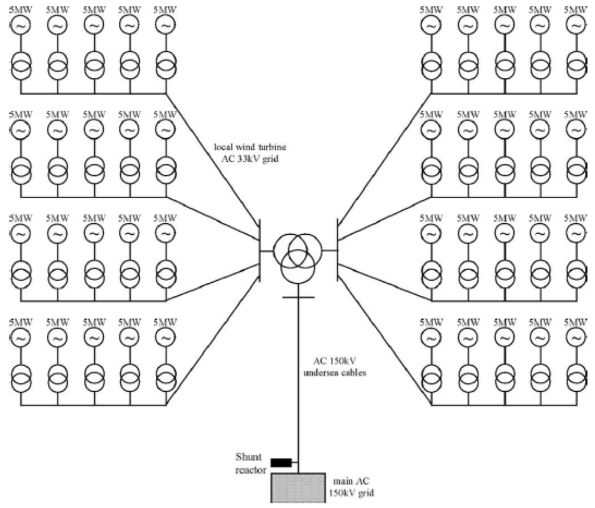


Fig. 1. Electrical system for ac connection of a 200 M…….,kkkkkW wind farm from [16].

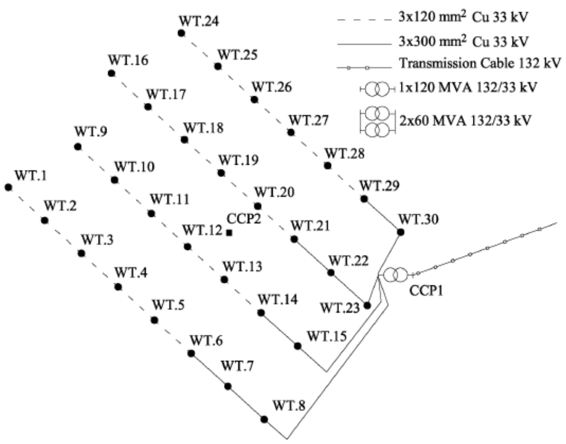


Fig. 2. Barrow offshore wind farm, [17].

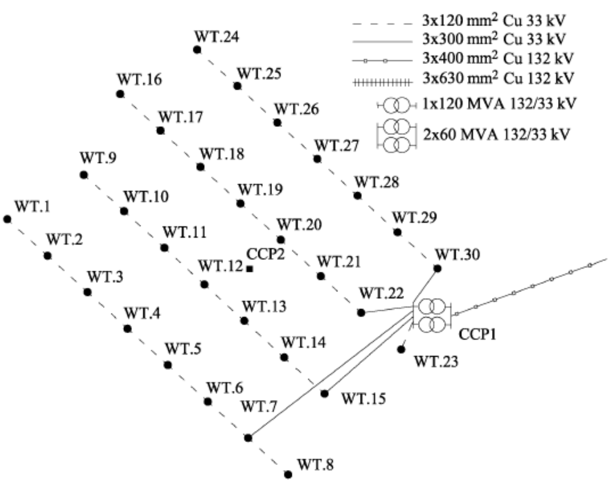


Fig. 3. Proposed optimal layout of the Barrow offshore wind farm, [17].

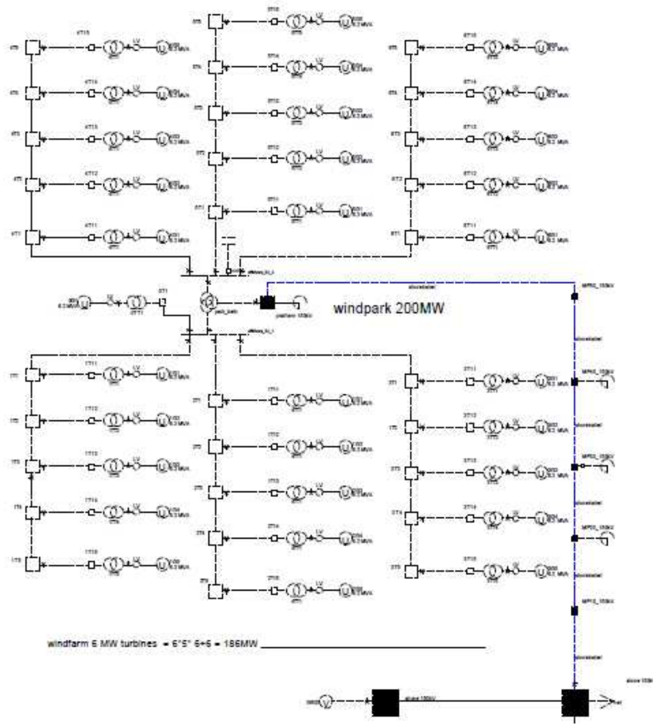
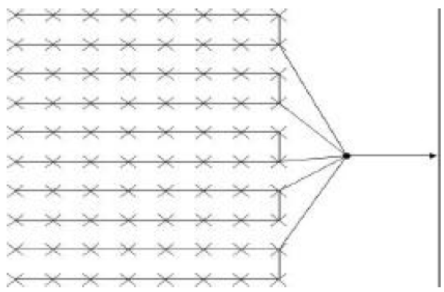
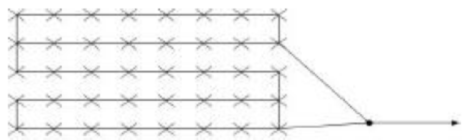


Fig. 4. Network layout, configuration and components of the offshore wind farm from [10].



a



b

Fig. 5. Horns Rev (a) and North Hoyle layouts (b), [15].

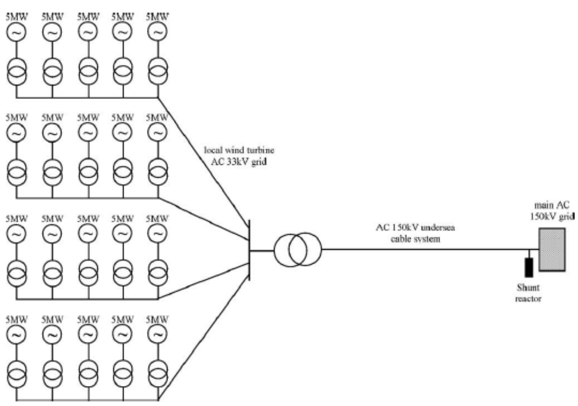


Fig. 6. Electrical system for ac connection of a 100 MW wind farm from [16].

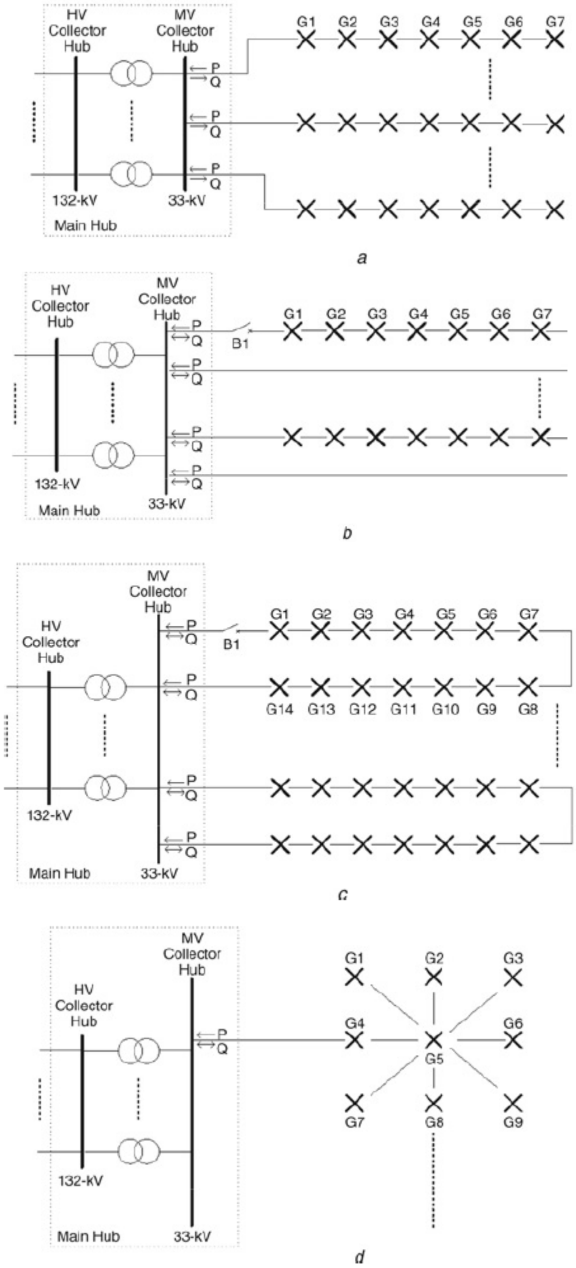


Fig. 7. Typical ORGS layouts and configurations: a) radial, b) single-sided ring, c) double-sided ring, and d) star, [18].

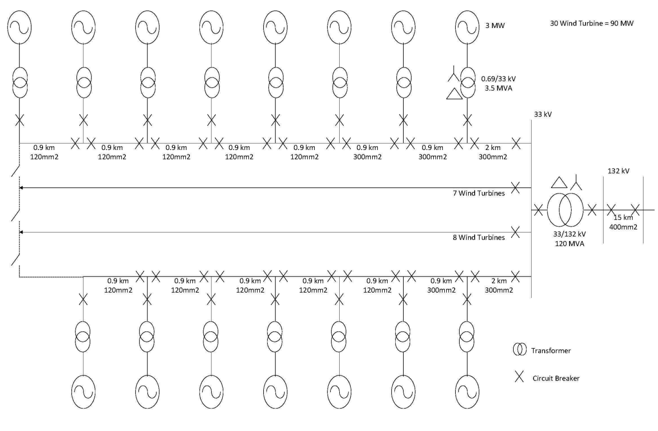


Fig. 8. Typical medium size ORGS configuration selected for the analysis ([3], [6]-[7], [15], [17]-[18]).

3.1 ANALYSED MEDIUM SIZE ORGS

Amongst the different ORGS configurations, Fig. 8 shows the one selected for the analysis in this paper, for which network and component parameters are listed in Table 3. The assessment compared the performance with and without normally open switches at the ends of the wind turbine radial strings (inter-array cables).

Table 3. Parameters of the typical medium size ORGS selected for the analysis, [19]-[23].

Component	R	X
	(p.u. on 100 MVA)	
33kV Submarine Cable (300 mm^2)	0.0073 per km	0.0104 per km
33kV Submarine Cable (120 mm^2)	0.0184 per km	0.0118 per km
132kV Submarine Cable (400 mm^2)	0.0004 per km	0.008 per km
Nacelle Transformer (0.69/33kV)		1.2
Transformer (33/132kV)	0.007	0.244

4. RELIABILITY ASSESSMENT: RESULTS

Over the last decades, the concept of reliability assessment evolved into the comprehensive approaches for evaluating various engineering strategies, typically linked to system planning, operation and maintenance studies. The meaning of reliability, which was initially expressed as the ability of a component to operate without faults during its lifetime and as specified by the manufacturer, has been generalized and now receives different connotations in engineering applications. This change is emphasized by the context in which reliability analysis of modern electricity networks, including ORGS, is not directly assigned to individual components in terms of the frequency and duration of their failures, but is extended and typically refers to the performance assessment of a whole system, subsystem, or part of a system which is of interest during the analysis. However, and as mentioned before, reliability performance of the whole system is indeed determined by the performance of its individual components. The reliability assessment in this paper was done using both analytical (i.e. deterministic) and probabilistic (i.e. Monte Carlo) approaches.

4.1 ANALYTICAL APPROACHES

Among the several techniques developed over the past years for the assessment of reliability performance, analytical approaches are often used for network planning or system security studies (e.g. "n-1 or n-2 security criteria"), as well as for evaluating network contingencies and system capacity/reserve requirements. It is generally assumed, however, that analytical reliability assessment approaches cannot directly or fully model inherently stochastic nature of system faults, or significant variations in fault repair times, or equally wide range of changes in system loading conditions.

Analytical reliability assessment approaches are based on mathematical models, which characterize analysed network in terms of the specified input data, typically limiting outputs to one set of results, e.g. mean values of reliability indices, corresponding to specified input mean data (e.g. average values given in Tables 1 and 2). In that way, analytical approaches offer only a general "snapshot" characterization of the analysed system, as they will always provide the same set of output results for the same set of input data, parameters and models. This is significant difference from probabilistic methods, which enable to perform a more comprehensive evaluation of system reliability with output reliability indices expressed as probability distributions (showing the ranges of their variations), rather than one set of output values and results (typically mean or average values).

4.2 PROBABILISTIC APPROACHES

Probabilistic reliability assessment procedures are widely recognized as more suitable for the analysis of system reliability performance, particularly in terms of their ability to model stochastic and inherently unpredictable variations of input parameters and data (e.g. fault rates and repair times) with their assumed probability distributions. Furthermore, probabilistic reliability assessment approaches allow to model a wider range of variations of practically all input parameters and data in one or few simulation/calculation set-ups, without the need to repeat calculation after a change in input data.

Although probabilistic reliability assessment procedures are more difficult for implementation (particularly in complex large-scale systems), they provide more accurate and more detailed results than analytical approaches. The most frequently used probabilistic reliability assessment approach is the inverse transform method, also known as Monte Carlo Simulation (MCS, [24]). Besides network modelling, conventional MCS analysis requires statistical information on fault rates and repair times of faulted power components as input data. Network models and fault rates of power components are used to establish which system components will be faulted (and how frequently), whereas repair times of faulted components and network protection, reconfiguration, switching and alternative supply functionalities are used to estimate durations of corresponding supply interruptions. The outputs of the MCS analysis are reliability indices, which are typically presented as probability distributions with the corresponding mean values.

4.3 ANALYTICAL ASSESSMENT OF THE ORGS RELIABILITY PERFORMANCE

As mentioned, the output of the analytical reliability performance assessment methods is one set of calculated indices and parameters, which are in this paper obtained using minimum, maximum and average values of fault rates and mean repair times from Tables 1 and 2, applied for the analysis of selected wind-based ORGS shown in Fig. 8. The assumed average capacity factor during the downtime was 40% (i.e. 40% of the rated power of all wind turbines which are not able to operate or export produced energy due to a fault or failure within the ORGS was assumed to be lost for the whole duration of the downtime event).

Table 4. Analytical reliability assessment of EENS (Expected Energy Not Supplied) index for selected typical medium size ORGS.

ORGS Design	Failure Rates and Repair Times	Exp. Energy Not Supplied (EENS) (MWh/year)	Estimated Profit Losses (£/year)
Without switches at the ends of radial strings	Minimum	308.824	43,235.36
	Average	33,176.501	4,644,710.14
	Maximum	136,605.506	19,124,770.84
With switches at the ends of radial strings	Minimum	244.408	34,217.12
	Average	31,167.430	4,363,440.20
	Maximum	129,414.100	18,117,974.00

The results from Table 4 show that somewhat better reliability performance is obtained if ORGS is designed with normally open switches at the ends of the radial strings of wind turbines, which will close after a fault in any of the strings is cleared and in that way provide connection of remaining wind turbines in a faulted string (downstream the fault location) to stay connected and export generated electricity.

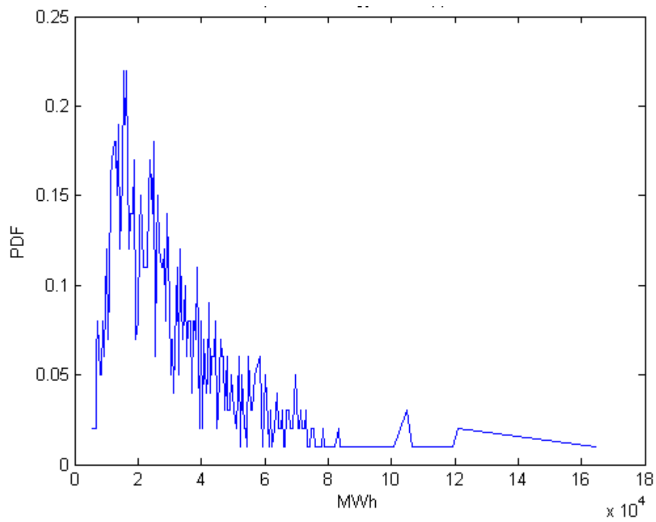
In order to assess the range of possible losses in profit and income due to the downtimes of wind turbines for any related fault within the ORGS, average cost of £140/MWh is assumed in the further analysis, [25]. If average values of fault rates and mean repair times are used, the estimated lost profit is about 10.5% of the total generated power outputs (£44,150,400) when no switches allowing connection at the end of the radial strings are installed, while this is reduced to about 9.9% if switches are installed.

4.4 PROBABILISTIC ASSESSMENT OF THE ORGS RELIABILITY PERFORMANCE

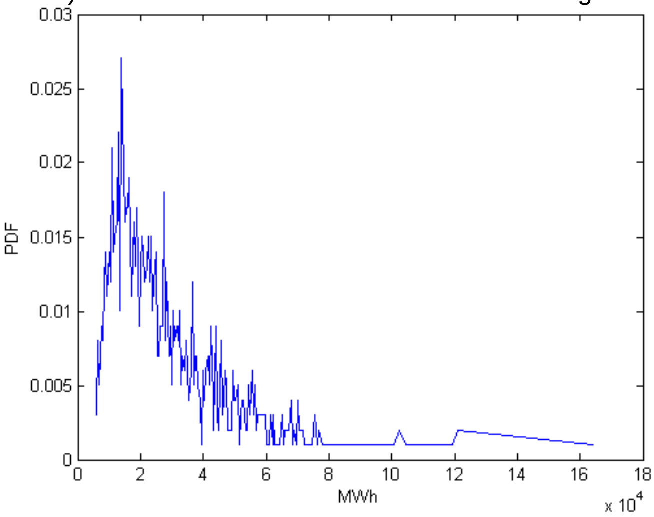
The results for the probabilistic reliability performance assessment (Monte Carlo approach, with 1,000 years of simulations) provide not just mean/average values for calculated indices and parameters (which closely match those calculated with analytical approach), but also provide their distributions. This is illustrated in Table 5 (mean values of EENS index for both analysed cases) and in Fig. 9 (distribution of EENS index values for both analysed cases), with again assumed average capacity factor during the downtime of wind turbines of 40%.

Table 5. Probabilistic reliability assessment of EENS (Expected Energy Not Supplied) index for selected typical medium size ORGS.

ORGS Design	Failure Rates and Repair Times	Exp. Energy Not Supplied (EENS) (MWh/year)	Estimated Profit Losses (£/year)
Without switches at the ends of radial strings	Minimum	292.80	40,992.00
	Average	31,237.06	4,373,188.40
	Maximum	111,491.34	15,608,787.60
With switches at the ends of radial strings	Minimum	217.736	30,483.04
	Average	29,457.7	4,124,078.00
	Maximum	106,945.01	14,972,301.40



a) without switches at the ends of radial strings



b) with switches at the ends of radial strings

Fig. 9. Distribution of EENS values (probability density function, PDF) for average input fault rates and mean repair times modelled with exponential distributions.

The results in Fig. 9 are in accordance with the data from Tables 1 and 2, which suggest that there is around 33-34 faults per year, most of which (but not all) results in a few/several wind turbines not being able to generate/export power, with average duration of repair times of about 390 hours, which gives the peak values of the PDF around few tens of thousands of MWh of EENS per fault event.

It is interesting to note that if the selected medium-size ORGS is designed with switches at the ends of radial strings of wind turbines, the improvement in the reliability performance is relatively small (~6%), as MV cables are reliable components, and also allow for a simple replacement, instead of a repair (these cables are modelled with 0.009116 faults/year and 752 hours of mean repair time, in accordance to Tables 1 and 2). In other words, investing in these switches may not repay.

5. CONCLUSIONS

Improving the reliability and availability of offshore generating plants and networks (i.e. reducing their revenue losses) requires correct assessment of the reliability of both the individual components and the complete offshore generation system. This paper presents the results of the reliability analysis of a typical medium size offshore wind generating plants and all interconnecting MV/HV networks.

In paper, both analytical and probabilistic approaches for the reliability assessment of offshore renewable generating system (ORGS) are implemented and compared, in order to obtain a more confident estimation of the ORGS reliability performance. In addition to the standard reliability indices (typically related to the frequency and duration of faults/interruptions), the paper provides results for energy-related reliability indicators (i.e. expected energy not supplied, EENS index).

The presented results compare the reliability performance of the selected ORGS for two different configurations(with and without switches at the ends of radial inter-array strings of wind turbines), in order to identify benefits of each considered network configuration in terms of the reduction of interrupted or curtailed energy outputs of ORGS, which are assessed against the actual cost.

Further work will assess risks and uncertainties in the reliability performance of ORGS based on the contributions of the individual ORGS components.

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SMART GRID FUNCTIONALITIES FOR IMPROVING RELIABILITY OF RURAL ELECTRICITY NETWORKS

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Keywords: Quality of supply, reliability assessment, rural networks, supply interruptions, smart grids.

Abstract

Most of the ongoing and planned "smart grid" activities are aimed either at densely-populated urban and highly urban areas (e.g. "smart cities"), or at sparsely-populated isolated off-grid areas (e.g. small islands and remote mountain regions). Rural areas, which are generally denoted as "thinly-populated", are somewhere in between these two and are to a large extent neglected in the anticipated transformation of existing networks into the future "smart grids" (SGs). It is currently not clear which of the SG technologies and functionalities could be successfully implemented in rural areas and how specific characteristics of rural networks will impact implementation of SG solutions developed for urban and isolated off-grid areas. This paper considers a number of options for improving reliability performance of rural LV and MV networks, including those that are generally denoted as SG functionalities. The considered options include: provision of alternative supply points, implementation of remote control, automation and reconfiguration capabilities, as well as adding redundant components and reducing fault response and supply restoration times. The results for standard reliability indices are calculated using analytical approaches and then evaluated in order to identify the best options for improving reliability performance of considered LV/MV rural networks.

1 Introduction

Power supply systems in urban and highly urban (e.g. metropolitan) areas are characterized by strong, meshed and short-length underground cable networks, featuring multiple control, automation and volt-var regulation options, as well as the provision of alternative supply points to a large number of connected customers, with highly concentrated energy demands. In-built flexibility and redundancy in the network design, as well as a close proximity of repair crews, influence that urban networks exhibit both low frequency of long supply interruptions and short duration of fault repair and supply restoration times, resulting in a very reliable and high quality electricity supply.

On the other hand, isolated off-grid communities are fully capable of operating independently from the mains grid supply and rely solely on available local resources, not on services, functionalities and supply from the grid. Furthermore, isolated off-grid communities own and operate their LV and MV networks and therefore share responsibility for maintaining desired or required reliability levels, e.g. through the direct control of non-essential loads for balancing demand with available generation. Due to a number of technical and economic factors (related to, e.g., availability of technical support and repair crews, limited investment potential, types and characteristics of protection systems, etc.), it is not unusual for isolated off-grid networks to experience very frequent and/or excessively long interruptions of supply, resulting in a poor reliability performance.

Due to the remote locations, highly dispersed customers and significantly lower demands, rural areas are typically connected to weak radial overhead networks, with long line lengths and high exposure to elements and harsh weather conditions (strong winds, high snows and rains, floods, etc.). Additionally, rural networks typically have no redundancy, no alternative supply points and feature only some limited automation and reconfiguration capabilities, resulting in a much higher frequency of both short and long supply interruption, as well as in the significantly longer supply restoration times. Finally, LV and MV networks in rural areas are owned and operated by distribution network operators (DNOs), who are ultimately responsible for maintaining required reliability and quality of supply performance.

Most of the ongoing and planned "smart grid" activities are aimed either at densely-populated urban and highly urban areas (e.g. "smart cities"), or at sparsely-populated isolated off-grid areas (e.g. small islands and remote mountain regions). Rural areas, which are generally denoted as "thinly-populated" (i.e. with less than 100 inhabitants per square kilometre), are somewhere in between these two and are to a large extent neglected in the anticipated transformation of existing networks into the future "smart grids" (SGs). Accordingly, it is currently not clear which of the SG technologies, functionalities and services for improved reliability performance could be successfully implemented in rural areas, and how specifics of both energy supplies and energy demands, as well as different characteristics of rural networks (in terms of network configurations and components, energy densities, etc.), will impact implementation of existing SG solutions for urban and isolated off-grid areas, but also deployment of genuinely new solutions, tailored for the needs and characteristics of the rural networks.

Improved reliability performance is often assumed to be one of the very basic aspects of the future "smart grids", which should also provide functionalities and services for reducing CO2 emissions and other drivers of climate change, while maintaining the highest possible levels of power quality, sustainability and affordability of electricity supply for customers. This is recognised, for example, in the latest review of the performance-based model that the UK Regulator (Ofgem) applies to all of UK DNOs: "Revenue=Incentives+Innovation+Outputs" (RIIO-ED1) [1]. The RIIO-ED1 control and regulation came in force in April 2015, encouraging DNOs to not only increase the use of low carbon and sustainable technologies, but it also set a higher requirements for reliability and quality of supply (e.g. duration of long interruptions after which customers are entitled to compensation reduced from 18 hours to 12 hours, while higher compensation schemes and penalties were set for implementation). Importantly, customers in Scottish Highlands and Islands, as well as the "worst served customers" in remote (i.e. rural) areas, are now fully included in the RIIO-ED1 network reliability regulation.

To answer some of the above mentioned challenges, this paper considers a number of options for improving reliability performance of rural LV and MV networks, including those that are generally denoted as SG functionalities ("smartification" after electrification). The considered options include: provision of alternative supply points, implementation of automation, reconfiguration and remote control capabilities, as well as adding redundant components and reducing fault response and supply restoration times. Presented results for standard reliability indices are calculated using analytical approaches and then evaluated in order to identify the best options for improving reliability performance of considered LV/MV rural networks.

A number of previous studies analysed the effect of SG applications on the reliability of distribution networks, e.g. [2]-[8]. The existing body of work, however, mostly addresses the SG functionalities for improving reliability of urban networks, while there is only a very limited number of references related to the improvement of reliability and quality of supply in rural areas, e.g. [9]-[11]. The analysis in this paper divides different SG options for improving reliability performance in several groups, based on both their costs and technical difficulties for their implementation in rural networks. Furthermore, typical UK/Scottish LV and MV rural network configurations are used for a detailed quantitative assessment of the effectiveness of the considered options in improving reliability performance, in terms of the reduced fault rates and restoration times.

The main purpose of this paper is to investigate applicability of some of SG functionalities in rural radial networks and to propose practical (i.e. cost-effective) solutions, possibly combining several options, for improving reliability performance and for meeting the regulator requirements for security, reliability and quality of supply, as in e.g. [1]-[4].

2 Methodology

2.1 Reliability Indices Used in Analysis

The set of five commonly used reliability indices is used in this paper for the assessment of reliability performance of considered LV and MV rural networks:

1. System average interruption frequency index (SAIFI), which calculates annual average number of long interruptions (with durations longer than 3 minutes in the EU, and 1 minute in the USA) for all customers in the considered network/system:

$$\mathrm{SAIFI} = \frac{\text{Sum of customer interruption}}{\text{Sum of customers Served}} \tag{1}$$

2. Momentary average interruption frequency index (MAIFI), where "momentary" is defined in the EU to be less than 3 minutes (1 minute in the US), which calculates annual average number of momentary/short interruptions for all customers in the considered network/system:

$$\mathrm{MAIFI} = \frac{\text{Sum of momentary interuption}}{\text{Sum of cusomers served}} \tag{2}$$

3. System average interruption duration index (SAIDI), which calculates annual average duration of long interruptions (in hours, or in minutes) for all customers in the considered network/system:

$$\mathrm{SAIDI} = \frac{\text{Sum of customer interruption duration}}{\text{Sum of customers served}} \tag{3}$$

4. Customer average interruption duration index (CAIDI), which calculates the average duration of long interruptions (in hours, or in minutes), i.e. the ratio of (3) over (1):

$$\mathrm{CAIDI} = \frac{\text{Sum of customer interruption duration}}{\text{Sum of customer interuptions}} \tag{4}$$

5. Average energy not supplied (AENS), which calculates annual average energy (in kilowatt-hours, or in megawatt-hours) not supplied to all customers in the considered system/network due to long supply interruptions, based on the durations of long interruptions and known or assumed customers' demands for all faults and for all customers in the considered network/system:

$$\mathrm{AENS} = \frac{\text{Total energy not supplied}}{\text{Sum of customers served}} \tag{5}$$

The main reason for selecting the above five reliability indices is to ensure that every aspect of the reliability performance analysis is properly assessed, as, for example, the implementation of one specific SG option might reduce frequency of long interruptions, but increase their duration.

2.2 Analytical Reliability Assessment Methods

Analytical or deterministic reliability assessment is based on the evaluation of known or assumed mean fault rates and mean repair times of all network components in a considered network model. The approach consists of evaluating consequences of permanent and transient faults of each network component in terms of the numbers of interrupted customers and corresponding supply restoration times.

Sum of annual fault rates (i.e. annual probabilities of faults) of all components resulting in the long or short interruptions of customers will give the total numbers of faults contributing to SAIFI in (1), or MAIFI in (2), respectively, when divided by the total number of served customers. Sum of products of fault rates and mean repair times (i.e. average duration required to repair the faulted component) of all network components that cause long interruptions of customers will give the total annual duration of long interruptions contributing to SAIDI in (3), again when divided by the total number of served customers. CAIDI in (4) is calculated by dividing SAIDI by SAIFI, while AENS is calculated using SAIFI, SAIDI and assumed or known demands of customers during the experienced long interruptions of supply.

The analytical reliability assessment approaches result in one set of output results (i.e. estimated frequency and duration of long interruptions, as well as frequency of short interruptions, from which system reliability indices (1) to (5) are calculated) for one set of input parameters and data (i.e. network configurations and components, corresponding fault rates and repair times, numbers and demands of customers, etc.). The calculated system reliability indices are represented as the mean (or average) annual values, and if any of input data or parameter changes, the analytical calculations should be repeated with the new set of input data. This is illustrated in Section 5, where each of applied options for improving reliability performance resulted in a new/separate analytical calculation, i.e. in a new set of calculated reliability indices (Tables 2 and 3).

2.3 Protection Systems

As previously mentioned, electricity customers in rural areas are typically supplied by longer-length radial overhead LV and MV networks, featuring limited or no automation and reconfiguration capabilities, no redundancy and no alternative supply points. Primary MV distribution substations (33/11 kV in the UK, Fig. 1) typically supply few radial 11 kV feeders, with around a dozen laterals ("spurs") with relatively equally distributed loads. MV feeder heads are protected by circuit breakers (CBs) with automatic reclosing (AR) functionalities, while only one or two main sections will have automatic sectionalisers (AS'), or automatic reclosers (ARs). Secondary distribution substations (11/0.4 kV in the UK, Fig. 2) supply 6-8 LV feeders, with a CB (no AR), or a fuse at the head, supplying 3-4 LV laterals with typically unequally distributed loads.

As the most common protection component is fuse (at all LV laterals and most of MV laterals), the settings of protection system will almost always utilise so called "fuse saving" scheme [12]. In this protection scheme, an upstream CB/AR will isolate fault before any of the fuses located downstream reacts. If the fault is transient (or temporary) and CB has AR, subsequent reclosing will restore supply, causing only a short/momentary interruption to customers and eliminating the need to dispatch service crew to replace blown fuse(s).

3 Input Data, Parameters and Networks Models Used for Reliability Assessment

3.1 Generic Rural LV and MV Networks

Typical rural LV and MV radial networks are identified from the UK/Scottish DNO reports and used as "generic rural networks" for the analysis in this paper, Figs. 1-2.

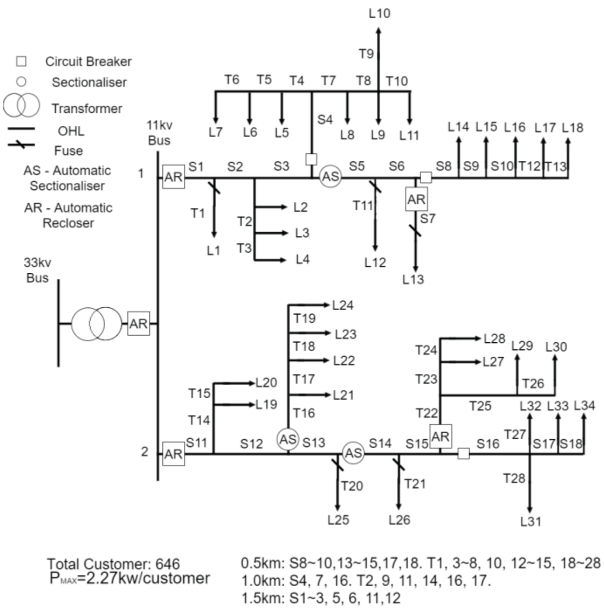

Fig. 1 Generic MV rural network used for the analysis

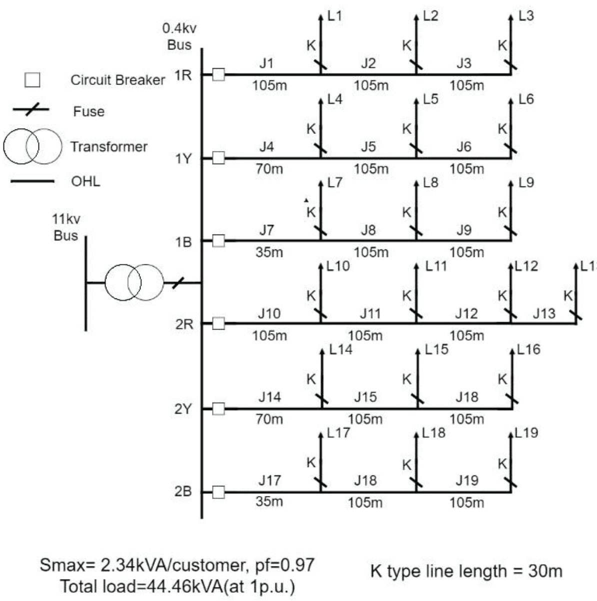

Fig. 2 Generic LV rural network used for the analysis

3.2 *Mean Fault Rates and Mean Repair Times*

Mean fault rates and mean repair times of network components are basic input data for reliability assessment. These are typically available from DNOs' annual reports to the regulator, or from the statistics that the DNOs are publishing on the performance of their networks, or from existing literature, e.g. [13]-[15]. Most of the DNOs, including those in the UK, provide only information on the overall reliability performances of their networks, with no distinction between different areas, or types of the networks. For example, a differentiation between the fault rates and repair times in urban, sub-urban and rural networks is usually not available from the published DNO data.

Fault rates and repair times used in this paper are taken from the UK-based statistics in [16] and additionally correlated with published EU-based data in [17], which also provides some limited information on transient and permanent faults, as well as on different types of the EU networks, based on population densities. Accordingly, Table 1 presents mean fault rates and mean repair times used for the analysis in this paper. The assumed percentage contributions of the transient faults and permanent faults to the total number of faults in rural networks are 76% and 24%, respectively. This information is required for the correct calculation of short and long supply interruptions (SAIFI and MAIFI).

Table 1 Mean fault rates and mean repair times used for the reliability analysis of rural LV and MV networks

Network Component	Mean fault rate (faults/year)	Mean repair time (hours/fault)
Transformer 33/11 kV	0.01	100
Transformer 11/0.4 kV	0.01	20
33 kV Bus	0.001	8
11 kV Bus	0.003	8
0.4 kV Bus	0.005	4
11 kV Overhead Line (per km length)	0.091	7
0.4 kV Overhead line (per km length)	0.168	6
11 kV Circuit Breaker or Automatic Recloser	0.0071	72
11 kV Automatic Sectionaliser	0.0071	36
0.4 kV Circuit Breaker	0.0071	36
0.4 kV Switch Fuse or Fuse	0.0027	3

3.3 *Load Profile of Customers in Rural Networks*

Load profiles of rural domestic (or residential) customers will vary based on the geographic location, size of the household and use of electrical equipment for specific activities, but can be generally represented by Fig. 3. The assumed "after diversity maximum demand" per household is 2.34KVA at 0.97 power factor [18].

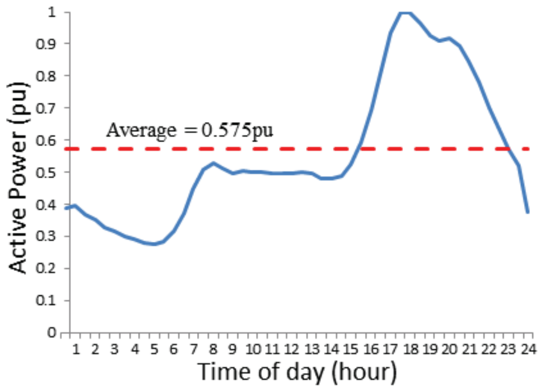

Fig. 3 Load profile of LV rural domestic customers

4 SG Options for Improving Reliability Performance of Rural Networks

This section discusses a number of options for improving reliability performance of rural LV and MV networks, including those that are generally denoted as SG functionalities.

4.1 *On-site Replacement of the Faulty Components, Instead of Repairing Them*

The values in Table 1 suggest that relatively long repair times are reported for faults of CBs, ARs and AS' at both LV and MV levels (between one and a half and three days). Due to the supply of relatively low demands in rural networks, these protection and switching components are compact and lightweight (see e.g. [16]), i.e. they can be easily transported by repair crew. This will then allow to replace faulty components on-site, instead of attempting to repair them, which is estimated to reduce supply restoration times related to the repairs of CBs, AS' and ARs in Table 1 for about 50%.

4.2 *Installation of Additional Lines at the Ends of the Feeders, or Provision of Alternative Supply Points*

Radial topology of rural LV and MV networks does not allow for an easy and economic implementation of network reconfiguration functionalities. However, "meshed/ring networks" can be formed by either connecting open ends of feeders supplied from the same primary/secondary substation, or an alternative supply point can be provided by connecting to nearby primary or secondary substation (supplying another LV/MV network). Longer lengths of feeders and larger distances from other rural networks will typically (but not always) result in high or even prohibitive costs of these options.

Additional lines for closing open ends of feeders should be equipped with protection devices, in order to prevent long interruptions of customers due to the faults on these additional lines. Coordination of the protection and sectionalising of main feeder sections also help to preserve supply to a larger number of customers, which would be otherwise interrupted. In Fig. 4, solid blue lines represent closed open ends, while dashed red lines represent alternative supply from a nearby network.

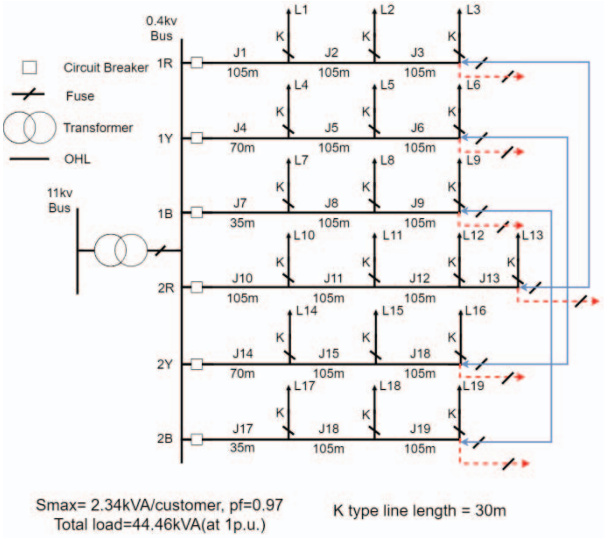

Fig. 4 Additional lines and alternative supply point (LV rural network)

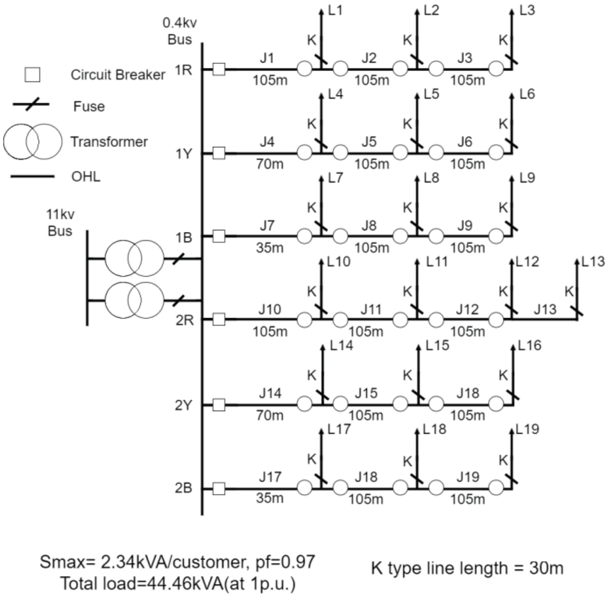

Fig. 5 Installation of additional components, or upgrading of the existing ones (LV rural network)

4.3 *Upgrading of Existing Components or Installation of Additional Components*

Installation of the additional redundant components, or upgrading of the existing components with those that will allow for the increased automation, or enable implementation of remote control, could also improve reliability performance of rural networks. For example, both primary and secondary substations in rural areas typically have only one transformer (Figs. 1 and 2), which will cause long supply interruptions of all customers connected to that substation in case of a transformer fault. If an additional transformer is installed, there will be two transformers (e.g. each with 60%-70% rating of the original one), providing redundancy and supplying either all, or most of the customers in the case of the transformer faults.

Another example is installation of additional CBs, or selective replacing of existing fuses with CBs (with or without reclosing and remote control functionalities), which could be additionally coordinated with AS'. The suitable locations are feeder main sections before/after laterals, indicated in Fig. 5, as this will improve network fault response through a better isolation of faults. A large number of combinations with newly installed CBs and with CBs replacing some fuses at various network locations is investigated, in order to identify the most cost-effective solutions, i.e. to find the optimal number of CBs (more expensive than fuses), that could provide the biggest improvement of reliability performance.

5 Results of Reliability Performance

5.1 *LV Rural Network*

Table 2 shows some of the results for the calculated reliability performance of generic LV rural network in Fig. 2 for a number of different options discussed in the previous section. The considered options/cases are:

- **Case 1:** Original LV network;
- **Case 2:** All faulted CBs are replaced, not repaired;
- **Case 3:** All CBs are equipped with AR function;
- **Case 4:** Open ends of LV feeders are closed with additional lines (LV network is meshed);
- **Case 5:** Open ends of LV feeders are connected with additional (normally open) lines to a nearby LV network, acting as an unrestricted alternative supply point;
- **Case 6a:** An additional CB is installed after the second main feeder section on each LV feeder;
- **Case 6b:** No CBs–only fuses are installed (at the LV feeder head and in each main feeder section;
- **Case 7:** The second transformer is installed in the supplying substation;
- **Case 8:** Combination of the Options 3, 4 and 6a (CBs with AR, additional CBs, alternative supply).

Table 2 Comparison of calculated reliability indices for considered options/cases (LV rural network)

Case	SAIFI	MAIFI	SAIDI	CAIDI	AENS (kWh)
1	0.0771	0	0.772	10.0	1.00
2	0.0771 (0%)	0	0.644 (17%)	8.36 (17%)	0.841 (16%)
3	0.0267 (65%)	0.0504 (-)	0.390 (50%)	14.6 (+46%)	1.00 (0%)
4	0.0700 (9%)	0	0.517 (23%)	7.38 (16%)	0.674 (23%)
5	0.0523 (32%)	0	0.290 (62%)	5.56 (44%)	0.379 (62%)
6a	0.0680 (12%)	0	0.799 (+4%)	11.7 (+17%)	1.04 (+4%)
6b	0.0637 (17%)	0	0.451 (26%)	7.08 (29%)	0.589 (41%)
7	0.0671 (13%)	0	0.574 (26%)	8.56 (14%)	0.749 (25%)
8	0.0125 (84%)	0.0280 (44%)	0.064 (92%)	5.11 (49%)	0.292 (71%)

5.2 *Discussion of Results for LV Rural Network*

The results in Table 2 demonstrate that implementation of practically all considered options have a positive impact on reliability performance (% reductions are also shown). MAIFI values cannot be calculated, as the original LV network is assumed to have CBs without AR functions, when all temporary faults result in long supply interruptions. (*Note: Self-extinguishing faults are not considered.*) Two exceptions are Cases 3 and 8, when CBs are equipped with AR functions.

Case 2: By replacing faulty CBs instead of repairing them, the corresponding supply restoration times will be reduced for around 50% (no impact on SAIFI), resulting in lower values of SAIDI and CAIDI, as well as AENS.

Case 3: After CBs are equipped with AR and set to operate in a fuse-saving scheme, significant number of temporary faults that previously resulted in long supply interruptions will now cause only short interruptions, dramatically reducing SAIFI, but increasing MAIFI.

Case 4: Forming of a meshed network provides alternative supply routes for faults on the main feeder. This is effective in reducing long supply interruptions caused by CB faults, impacting SAIDI and CAIDI values. However, network still has limited ability to isolate faults, requiring additional components for the further improvement of reliability indices.

Case 5: Similarly to Case 4, provision of alternative supply point effectively prevents supply interruption caused by the faults of the transformer, busbar and fuse in substation. It is more efficient compared to Case 4.

Case 6a: Additional CBs help to isolate faults on the main feeders, reducing SAIFI, but slightly increasing SAIDI and CAIDI values, due to the longer restoration times of additional CBs. This suggests that it would be effective to combine installing of additional components with the lines closing the ends of the feeders to reduce the impact of the faults on the main feeder.

Case 6b: Fuses are installed in every section of the main feeder, increasing fault isolation capability and reducing SAIFI (compare with Case 6a), but an increase in system fault rates due to the installed new fuses negates the effect of the better fault isolation.

Case 7: Additional transformer provides redundancy in case of a single transformer fault, but it is less effective than Case 5.

Case 8: This case demonstrates the effects of combining several options. Provision of an alternative supply point, or closing of the open feeder ends in meshed network configuration, with the implementation of additional CBs with AR functionalities, significantly increases network's ability to isolate faults and limit their impact in terms of frequency and duration of supply interruptions, as well as the number of interrupted customers (last row in Table 2).

Despite their positive effects on improving reliability performance, the implementation of some of the considered options might incur very large costs, or might not be possible at all. Although this will in principle depend on the actual characteristics of the considered rural LV and MV networks (e.g. network configuration, number of loads and their distribution), it is possible to perform a general (pre)evaluation of the costs and benefits of multiple options.

This is illustrated in Fig. 6, which presents a "cost-benefit flow chart", where different options should be selected for further evaluation and implementation starting from the upper-left corner (low cost and high impact) and then progressing to the right. If an option is not economically viable, selection proceeds by going vertically down (e.g. from the provision of alternative supply point, to the realisation of the meshed network configuration, to the installation of the additional transformer). This approach also allows for combining different options to maximise their effects on improving reliability performance of rural LV and MV networks.

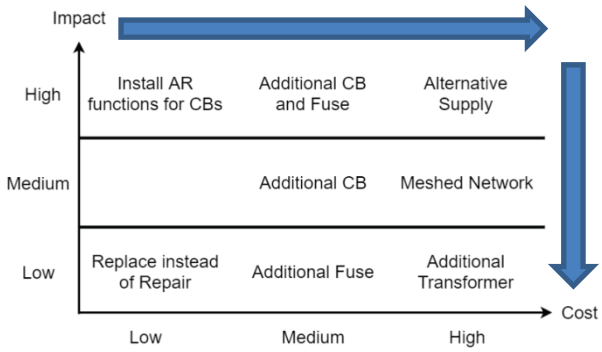

Fig. 6 Cost-benefit evaluation flow chart of different options for improving reliability of rural networks

5.3 *MV Rural Network*

Configurations of rural MV networks are similar to rural LV networks (Figs. 1 and 2), which basically means that same options for reliability performance of LV network from Sub-sections 5.1 and 5.2 could be evaluated and implemented for the rural MV network. With reference to Table 3, the following cases are considered:

- **Case 1:** Original MV network;
- **Case 2:** All circuit CBs are equipped with ARs and an unrestricted alternative point of supply is provided form a nearby MV network;
- **Case 3:** All circuit CBs are equipped with ARs, an additional transformer is installed in substation and additional lines to connect open ends of main feeders are installed to form a meshed network;
- **Case 4:** All CBs are equipped with ARs and instead of repairing the faulted components, they are replaced on the site.

The results for the same system reliability performance indices considered before in case of generic rural MV network from Fig. 1 are listed in Table 3.

Table 3 Comparison of calculated reliability indices for considered options/cases (MV rural network)

Case	SAIFI	MAIFI	SAIDI	CAIDI	AENS
1	0.316	0.321	4.24	13.4	3.59
2	0.118 (62%)	0.207 (36%)	1.01 (76%)	8.63 (36%)	0.857 (76%)
3	0.126 (60%)	0.210 (35%)	1.87 (56%)	14.8 (+10%)	1.59 (56%)
4	0.197 (38%)	0.529 (+65%)	3.35 (21%)	17.0 (+27%)	2.83 (21%)

5.4 Discussion of Results for MV Rural Network

As the considered generic MV network in Fig. 1 already has some ARs and AS', adding more of these components will have only a minor impact on the improvement of reliability performance. Therefore, these cases are not considered.

The results for the three considered cases generally follow the chart in Fig. 6. As previously discussed for rural LV networks, the results for Case 2 (indicating options in the top row of the chart in Fig. 6) represent the biggest improvement of reliability performance. Cases 3 and 4 correspond to the options from the bottom and central parts of the chart, which are less effective, but still result in significantly better reliability performance than that of the original network. It should be noted that the calculated increase of CAIDI values for Cases 3 and 4 are result of the corresponding relative changes (i.e. disproportionate reductions) of SAIFI and SAIDI values. In other words, Cases 3 and 4 are not "worse", or less reliable than the original network (Case 1), as the implemented options have different effects on reducing frequency and duration of long interruption with respect to the initial values of Case 1.

6 Conclusions

Stricter regulation (i.e. higher penalties/compensations) forces DNOs to improve reliability of supply to all customers, including those in rural areas. Although improved reliability performance is one of the very basic aspects of the future "smart grids", most of the ongoing and planned "smart grid" activities are aimed either at urban areas, or at isolated off-grid areas. Rural areas are somewhere in between these two and are to a large extent neglected in the anticipated "smart grid" transformation of existing networks. This paper investigates applicability of a number of ("smart grid") options for rural networks and evaluates practical cost-effective solutions for improving their reliability.

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